

Leveraging Network Utility Asset Management Practices for Regulatory Purposes

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Background and Objectives of this Report

Many utilities around the world are entering a significant asset renewal phase requiring increases in asset replacement and refurbishment budgets. These utilities are also facing demands for modernization and implementation of intelligent network (Smart Grid¹) technologies; these are in large part still conceptual ideas around which there is considerable uncertainty. Against this background, it is essential that these utilities implement robust yet flexible asset management practices in order to optimize system architectures, asset replacements, and future operating costs. In recognition of these issues, KEMA was commissioned to provide this report on the ways in which regulators assess investment plans, with a focus on the implicit or explicit use of asset management approaches, including principles, processes, inputs and outputs, decision-making criteria and prioritization methods. The objective of this report is to ensure that OEB staff is familiar with the principles and objectives of established and emerging asset management practices and underlying analytic processes, systems and tools, so that investment information provided by network utilities in rates and other applications can be evaluated effectively.

The Need For and Importance of Asset Management

The fundamental principles of asset management are to most effectively manage the business assets in order to optimally meet the requirements of all stakeholders. This includes the need to meet the short-term aspirations of the business with the long-term need for flexibility and sustainability in the business. These principles require asset management practices to balance cost, performance and risk; and to align the organizational objectives with investment decisions.

Investments in electricity network infrastructure occur over extended periods, typically decades. The design life of the primary assets employed within such networks is typically in the range of 40 – 60 years, so many utilities are now entering a significant asset renewal phase. This phase requires increases in asset replacement and refurbishment budgets as aging infrastructure assets approach the nominal end of life. It also requires the competence for effective innovation: to identify new technologies, to integrate new systems with old, and to deploy innovation to full effect in the business. The importance of adequate asset management processes, systems and implementation will become increasingly relevant in future years to ensure that uneconomic investments can be avoided without jeopardizing overall network integrity or the flexibility required where facing an uncertain future. It is therefore appropriate for regulators to seek evidence of asset management competence when assessing investment submissions from utilities. Such assessments provide assurances that the utilities understand and have prioritized their investment plans, that the investment requirements are not

¹The “Smart Grid” has no common international definition, but there is an emerging consensus that a radical change of electricity system architecture at all levels will be necessary to achieve the sustainability targets declared by many governments, to promote energy efficiency, to manage the impact of variable generation in a cost-effective way, to enhance supply security, and to raise the supply quality. Current technologies, including power electronics, dispersed intelligence, automation, and data communication, are key enablers and make the prospect of a modernised grid a reality. Comprehensive Research & Development is needed for the medium and longer term.

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overstated, that the benefits of innovation are not foregone, and that customer risk exposures are properly considered.

Further Details of International Markets and Their Regulatory Approaches to Asset Management

In producing this report for the OEB staff, KEMA has drawn upon an extensive review of regulatory approaches adopted for asset management practices in a selection of international energy jurisdictions; namely:

- Australia
- Germany
- Great Britain
- New Zealand
- USA
- Canada (British Columbia)

For each of the above markets, KEMA has provided detailed information regarding:

- Characteristics of utilities affected;
- Assessment of utility investment plans;
- Regulatory information requirements;
- Explicit asset management requirements;
- Relevant regulatory instruments;
- Regulatory guidance to utility companies; and
- Lessons learned and future areas of focus including innovation.

This information has been collated in a stand-alone document of Appendices that has been provided separately to the OEB staff to act as a reference source for those interested in understanding greater detail about the international markets and their regulatory approaches to asset management.

Regulatory Approaches for Review of Asset Management Underlying Investment Plans

This section outlines a number of assessment approaches, methodologies, and tools that regulators can apply in their review of network utility investment plans and the broader asset management practices which network utilities employ. The following list shows ten different methodologies, tools and approaches that are utilized by different regulators to deliver regulatory effectiveness in the context of their respective jurisdictions and governance frameworks. We also comment where appropriate on the impact that different approaches may have on the wider relationship between regulator and regulated company. The relative importance and extent of use of each of these ten regulatory approaches is discussed below.

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- 1) **Ex ante assessment** – this approach was universally adopted by all the jurisdictions reviewed and was applied in all contexts; its use is necessary to ensure cost control and protect consumers from monopoly abuse.
- 2) **Ex post assessment** – use of this approach was limited to Great Britain; it is typically used where materiality is high (e.g., large utilities, large overall spend) and high uncertainty exists at the time of ex ante assessment (e.g., volatile economic climate, unpredictable connection activity).
- 3) **Expert third party input** – this approach was used by most jurisdictions (Australia, Great Britain, US, New Zealand) and was especially applied for review of large utilities and/or large numbers of utilities to provide specialist depth of knowledge to combat information asymmetry and/or provide resources to deliver the scale of review.
- 4) **Periodic multi-year controls** – used by most jurisdictions (Australia, Great Britain, Germany) for maintaining systematic understanding and control of investment and asset management activities, especially for large network utilities with significant spend and impact on customers.
- 5) **Review of practice versus policy** – limited to Australia and Great Britain; important where strong focus on asset management and/or high materiality and high uncertainty exist at time of ex ante assessment; important for large networks, increasingly material investment amounts, and increasing network impact on customers.
- 6) **Reporting and monitoring** – used by most jurisdictions (Australia, Great Britain, US, New Zealand) to combat information asymmetry and retain “corporate memory of regulator” in situations with large numbers of utilities, large amounts of data, and/or extended periods of time between major reviews.
- 7) **Intervention triggers** – use limited to Great Britain and Australia (each in extremis), US and Germany (in limited manner); typically applied where high uncertainty at time of ex ante assessment and/or strong focus on performance delivery; also useful to protect customers where regulation is light due to utility size or numbers. To avoid regulatory uncertainty, utility and regulator must have clear view of consequences of reaching an intervention trigger.
- 8) **Benchmarking** – used in most jurisdictions (Australia, Great Britain, US, New Zealand); enables strong understanding of relative performance, and where peers exist, driving peer competition; especially used when many utilities are within the market, but also used for larger investor-owned utilities.
- 9) **Incentives** – informational and/or financial, can be very effective, used by most jurisdictions (Australia, Great Britain, US, New Zealand); useful where strong

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regulatory focus is on influencing specific aspects of utility activities/behavior; important where regulators actively seek to influence utility behavior (e.g., Great Britain, US FERC).

- 10) **Output measures** – emerging approach with limited current use; useful option to ex post assessment applied in the same context; sought to be applied where particularly strong regulatory focus on influencing a balanced approach to asset management (cost, risk, sustainability) and where there is otherwise strong information asymmetry by making explicit relationships between investment and different measures of performance; can be targeted on parameters that directly benefit customers; applied where regulators seek to influence behavior ex ante rather than ex post.

Overview of International Regulatory Practice for Review of Network Utility Asset Management

The key themes and observations that emerged from the review of the international regulatory practices are as follows:

- 1) **With one detailed exception, no jurisdiction explicitly requires specified asset management practices nor explicitly specifies compliance with a recognized asset management standard.** Only New Zealand has explicit reference in legislation (namely as part of the information disclosure requirements within the Commerce Amendment Act) which specifically states that an asset management plan may be required. However, all other jurisdictions drive the need for certain asset management practices (and in the case of Great Britain, the encouragement for company compliance with the asset management standard PAS 55) indirectly via their expectations of supporting evidence for investment plan requirements, indicated financial benefits of having asset management practices, and/or indicated disallowances for not having them. This is typically demonstrated by acceptance of submitted investment plans (and thus level of funding), but also can be driven or influenced by utility performance goals.
- 2) **Very different approaches are adopted across the different markets.** For example, the US and Germany are legalistic, whereas Great Britain and Australia/New Zealand are more economic/technical. This variation reflects differences in philosophy on market regulation (including recognition of subtle cultural differences), but also the age of the networks and the level of maturity of network utility regulatory processes (e.g., Great Britain is relatively mature while Germany is emergent). Prescriptive approaches, for example, having rigid frameworks and close regulatory oversight, may have the advantage of initial regulatory comfort, but are unlikely to encourage flexibility, open dialogue, risk management and entrepreneurial thinking in the companies. In the extreme case they

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may lead to risk aversion and a dependency culture where the “regulator does the thinking” and therefore “takes the risks”.

- 3) **Varying degrees of regulatory focus on asset management practices.** Asset management is a core central aspect of regulatory processes in Great Britain, Australia, and New Zealand, but is very limited in Germany and the US markets. This situation is reflected in the rigor of explicit requirements/guidance and the extent of implicit regulatory expectations. In our view, Great Britain’s regulatory approach to asset management represents leading international practice. The Great Britain approach also encourages an effective relationship between the regulator and company, where responsibility and accountability are clearly with the asset owner, but due regulatory oversight is not foregone.
- 4) **Varying levels of depth/sophistication of regulatory assessment.** Great Britain is at the forefront and has been driven primarily by aged networks and rapidly escalating asset replacement needs. It also has four years experience of incentives for network innovation, recognizing the wider challenges ahead of sustainability and smart grids. Great Britain benefits from over 20 years of experience with networks in a deregulated energy market. Germany is the least sophisticated in its review of asset management as its regulatory regime is still developing.
- 5) **Different approaches are used for gas versus electric utilities.** All the market regulators recognize the inherent differences that currently exist in the nature of gas versus electricity and transmission versus distribution within the detailed aspects of their regulatory approaches. (It is interesting to note in passing that the international vision emerging for smart grids has much less distinction between transmission and distribution and perhaps in the long-term there will be a convergence here.)
- 6) **Different approaches are used based on scale of the utility.** This finding is evident in markets where such scale issues are most apparent, such as Germany, and to a lesser extent, New Zealand.
- 7) **Aspects of regulatory approaches in other international markets provide positive learning points for Ontario.** There are aspects of regulatory approaches in all of the markets which provide learning opportunities for application in Ontario, including:
 - a) The decision by New Zealand to only apply information disclosure, and not default price-quality regulation, to the small customer-owned distribution utilities.
 - b) The importance of using third party independent technical experts to review the capital expenditure and asset management plans in Great Britain, Australia, and New Zealand.

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- c) Recognition of special circumstances requiring flexibility on the level of price control applied for different companies.
- d) The changing regulatory landscape being brought about by a combination of the increasing volume of asset replacement and the challenges of smart grids and sustainability. For example, the innovation incentives introduced in Great Britain are a leading development.
- e) Where the context within which the network utilities are operating or will need to operate is substantially changing and/or there are strong asset management challenges posed by aging network infrastructure; it is clear these are most effectively and efficiently met where the network utilities and regulators have constructive working relationships and focused dialogue on these asset management issues. Good examples of this are Australia and Great Britain.

Evaluation of Regulatory Approaches and International Regulatory Practices for Review of Asset Management

KEMA evaluated the different regulatory approaches and international regulatory practices along two dimensions:

- 1) The refinement of the regulatory review process related to asset management practices (i.e., what is done in the process). The position along this dimension indicates the relative degree of sophistication of the process (i.e., higher values indicate greater sophistication); and
- 2) The strength of regulatory guidance and assessment relative to asset management practices (i.e., how it is done in the process). The position along this dimension indicates the degree of regulatory engagement on asset management.

Based on the emphasis placed on these two dimensions, the different approaches could be mapped into four quadrants, as illustrated below.

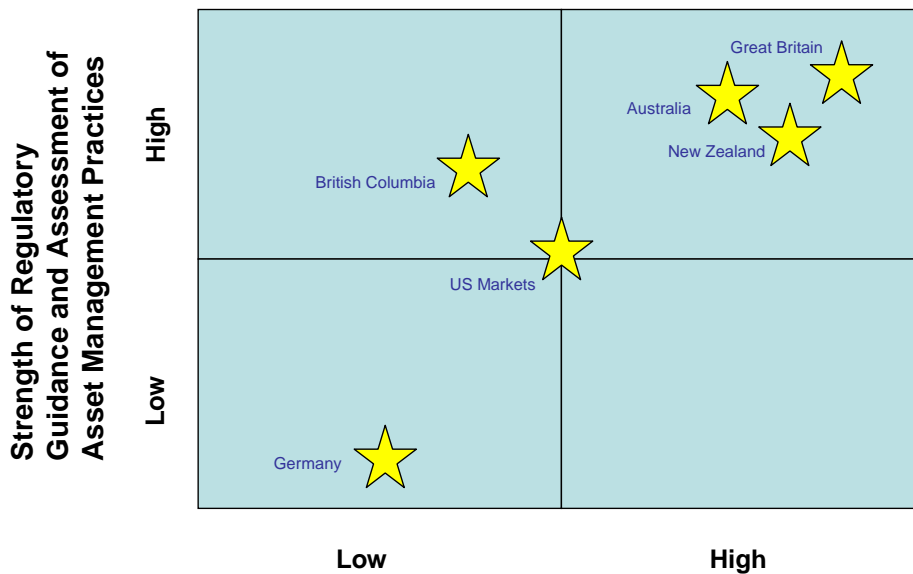
Figure 1: Comparison of Regulatory Approaches

Strength of Regulatory Guidance and Assessment of Asset Management Practices	High	Extensive and detailed guidance and assessment requirements encourage strong asset management, but regulatory review process does not place key focus on asset management issues in determination of rates/revenues - has some limited influence on network utility asset management practices; will depend on utility view	Guidance on, and review of, asset management practices is extensive and detailed; with the regulatory review process placing it at the heart of the revenues/rates determination process – this ensures uniformly strong network utility asset management practices at a detailed level
	Low	Asset management is not a focus for guidance or assessment and is a minimal element of regulatory review process in determination of revenues/rates – no influence on network utility asset management practices, which are typically weak	Regulatory review process provides incentives for strong asset management by treating it as a key focus, but level of guidance and/or assessment is limited or conducted at high level – influences good asset management practices based on key principles and objectives; but performance will vary by utility
		Low	High

Refinement of Regulatory Review Process for Asset Management Practices

In this context, the diagram below illustrates the perceived position of the different jurisdictions which KEMA reviewed. A high y-axis position should not be interpreted as indicating a highly prescriptive approach by the regulator.

Figure 2: Comparison of International Jurisdictions



Refinement of Regulatory Review Process for Asset Management Practices

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Based on this mapping and a review of the regulatory approaches used by the respective jurisdictions, different options can be identified for strengthening either dimension. These options are discussed below.

Options for Strengthening Regulatory Guidance and Assessment

- Indicate/specify expected level of asset management practices to provide clear signals/incentives to utilities and enable an auditable asset management process – this option is most apparent in Australia, Great Britain, and New Zealand, and is increasingly prevalent due to aging assets.
- Utilize expert independent assistance in assessing key aspects of asset management practices – this option is universally utilized by regulators, especially in areas of specialized expertise and where seeking international knowledge. It provides access to greater resources, objective perspectives, alternative views, expertise in specialized areas, and makes the regulator’s case more robust against challenge.
- Utilize appropriate and effective benchmarking to assess, promote and provide incentives for best practices and steer clear of the potential perverse incentives – this option is most apparent in Australia, Great Britain, US and New Zealand.
- Establish key measures and targets for performance – most apparent in Australia, Great Britain, US and New Zealand; can be specified in line with regulatory objectives and focused on key desired outcomes, ideally that have direct customer benefit; some measures can be fixed over time, whereas others can be refined as the market context, regulatory objectives and experience evolve.
- Utilize a relevant mix of top-down and bottom-up assessment techniques – this option is most prevalent in Great Britain, but is emerging in jurisdictions where aging assets and escalating capital expenditures are a major issue; it enables a robust assessment of asset management and derived investment plans, and enables review of feedback loops.

Options for Refining the Regulatory Review Process

- Apply a fit-for-purpose approach based on scale and/or type of utility – this option is almost universally applied where relevant (evident in Germany and New Zealand); it recognizes the materiality of impact of asset management practices and the resource capability of organizations to engage in the regulatory process.
- Establish consistency and predictability in process, information, and tools – almost universally used by regulators outside North America, most apparent in Australia and Great Britain; it makes the process easier to administer, allows for the development of corporate memory, facilitates the establishment over time of coherent data and information history, and enables comparability of information between peer utilities.
- Enhance transparency and engagement of stakeholders in the process – while this option is increasingly used by regulators worldwide, the means of achieving it varies widely based on relationship and style; it increases the information and insights a

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regulator has at its disposal and highlights stakeholder priorities and objectives, which can provide greater visibility of company actions in relation to stakeholder feedback.

- Establish regular performance reporting – most apparent in Australia, Great Britain, US and New Zealand; it further improves regulatory oversight by providing detailed annual monitoring capability; acts as a bridge between main reviews and reduces the need for “starting fresh” each cycle; reduces incentives for gaming; and highlights any emergent issues such that there are no undue surprises at the next cycle.
- Establish periodic cyclical regulatory review of comparable utilities – almost universally used by regulators outside North America, evident for example in Australia, Germany, and Great Britain; it allows intensive assessment of asset management practices over extended periods, enables smoothing of overall regulatory workload by staggering of reviews for different collectives of utilities; facilitates effective staffing and application of expertise; can drive economies of scale and synergies across collective utilities; enables effective benchmarking; facilitates greater transparency of process and easier engagement of stakeholders.
- Move away from legal-based approach – a non-legal based approach is used primarily by regulators outside North America, evident for example in Australia, Germany, and Great Britain; it allows for dialogue between relevant individuals and interests within both regulator and utility; facilitates greater degree of contact and iteration between regulator and utility to explore issues related to asset management; enables utilities to be more open about disclosing weaknesses of processes and practices, risk management and plans for development.

Applicability for Ontario of Potential Regulatory Approaches and International Regulatory Practices for Review of Asset Management

Based on a review of regulatory approaches, the varying extent of their application in international jurisdictions, and the specific market context of Ontario, KEMA identified specific approaches that may be most beneficial to the OEB staff.

1) Fit-for-purpose approach based on scale and type of utility

The divergence of size for utilities in Ontario emphasizes the need to apply a fit-for-purpose approach that considers differing scope, detail, and intensity of asset management practices within regulatory reviews of large versus small utilities to reflect the relative scale, sophistication, and materiality of impact on customers.

2) Indicate/specify expected level of asset management practices

This is an approach that OEB staff could readily introduce in the short-term by issuing guidance on expectations for asset management practices to utilities within its jurisdiction. Such guidance would be especially beneficial, given both the size and scale

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of network utilities in Ontario, as it could specify a minimum set of principles/level of performance deemed by the OEB staff to be appropriate. Furthermore, under a fit-for-purpose regulatory approach, OEB staff could highlight different minimum expectations based on the scale of the utilities.

3) **Use of expert third party independent assistance to review asset management**

The use of third party independent resources would provide OEB staff with access to additional expertise with knowledge of asset management practices in Ontario and other jurisdictions and/or industry sectors. Such expert input could easily be incorporated within the existing rates review hearing process, since it would simply mean addition of an intervener - which should not be contentious given asset management plans are already being submitted under the current review process. The use of an expert independent resource on asset management would also facilitate knowledge transfer to strengthen the understanding of asset management concepts and practices by OEB staff.

4) **Benchmarking of asset management practices**

Benchmarking is a key tool that OEB staff could apply given the high number of network utilities in Ontario. It would enable OEB staff to establish comparative performance and identify aspects where different utilities under (or over) perform against their “average” peer comparators; and also enable establishment of leading practice or performance frontiers to which all peer utilities are challenged to achieve. The application of benchmarking may be hampered by the fact that not all distribution companies have their rates reviewed simultaneously. Consequently, the OEB staff might wish to conduct an initial benchmarking exercise outside the ongoing rates review process, and then seek to roll it into future rate case reviews.

5) **Consistency and predictability in process, information, and tools**

A standardized and consistent/predictable review process can make the process easier to administer, allow for the development of corporate memory, facilitate the establishment over time of coherent data and information history, and ensure comparability of information between peer utilities and/or other industry sectors. It also minimizes the likelihood of regulatory uncertainty that can be a significant barrier to investment.

6) **Annual performance reporting and monitoring framework**

Finally, the establishment of annual performance reporting and monitoring is an emergent feature internationally that OEB staff could consider adopting as a complement to periodic regulatory review of network investment plans. Examples of these reporting frameworks are available from Australia, Great Britain, and New Zealand. KEMA suggests OEB staff could consider implementation of its own annual performance

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reporting and reporting framework as it can provide a number of benefits in the Ontario context.

For the Future: The Asset Management Implications of Sustainability and Smart Grids

New grid architectures and operating approaches is an international theme that is receiving considerable attention. The evidence emerging suggests that today's grids and their owners face fundamental changes and there are benefits to be obtained for supply quality, supply security, energy efficiency, sustainability, and cost-effectiveness. There are many implications from this but a key one is assets and asset management for the future. It may be of value to the OEB staff to look more closely at the nature of innovation on electricity grids, the pitfalls and opportunities, and consider the merits of incentivization and policy adaptation. Stakeholder dialogue is emerging as a key process in the jurisdictions where fundamental changes are receiving attention. This topic is wide in scope and goes beyond the remit of this review; OEB staff may want to consider developing it further as a separate item for the future.

KEMA believes the six approaches described above would be of particular benefit to OEB staff, given the Ontario market context. However, clearly OEB staff is in the most informed position regarding its regulatory priorities, and as such the above items are put forward as ideas for consideration rather than recommendations.

Assessment Criteria for Consideration by the OEB Staff

The panel below identifies a series of wider factors that a regulator might wish to consider when evaluating the introduction of new asset management policies.

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Policy Assessment Criteria		
For the new policy being considered....		
1	Does the regulator have the legal vires to implement this?	
2	Will the implementation proposal be sufficiently robust to external challenge?	<ul style="list-style-type: none"> - Availability of a Regulatory Impact Assessment - National or International benchmarks or references - Hard evidence not simply “best judgment”
3	Is this proposal consistent with other policy developments?	
4	Is the regulatory burden understood and accepted?	<ul style="list-style-type: none"> - Resources - Budget - Specialist skills - Need for external support
5	Have the reporting requirements been assessed and deemed acceptable?	<ul style="list-style-type: none"> - Data volumes - Practicability of reporting time-cycles - Workload peaks/troughs
6	Will the policy enhance the desired style of relationship with the regulated companies?	<ul style="list-style-type: none"> - Balance of responsibilities and accountabilities - Tendency for regulatory micro-management - Company proactivity
7	Where are the companies now as regards proactive behaviors; how will they respond?	
8	Does the policy have longevity; should it be implemented in stages?	<ul style="list-style-type: none"> - Ability to adapt or extend - Modify in light of experience
9	If incentives are proposed, is the data sufficiently robust?	<ul style="list-style-type: none"> - To audit standard if finance consequences - Consistency of data definitions between peer companies
10	Scope for company gaming; regulatory counter-moves?	

Final Summary of Observations

International evidence shows there is a growing realization of the increased capital expenditure needed to cope with aging assets and the changing requirements for network operation, including smarter grids. Given these issues an implemented asset management strategy and plan is an essential requirement that regulators should expect in order to determine that planned capital expenditure represents a good balance of risks, costs, performance, and future-proofing.

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This international review shows there is no single approach that is universally applied across countries or particular standards that are being adopted by regulators. One common theme is the rising importance that is being applied to asset management and the increased range of reporting mechanisms and assessment processes that are being applied in many regions.

It is KEMA's observation that the alternative approaches to asset management are likely to result in direct and indirect influence on the nature of the relationship between regulator and regulated companies in the medium and longer term. This may introduce a need to make a balanced choice, i.e., accept some element of trade-off, in the model chosen.

There are a number of options that could be applied in Ontario to increase the level of scrutiny applied to asset management practices. Some of these options require significant changes to the regulatory framework, and a fuller assessment of the benefits would be needed before adoption; other changes could be undertaken within the current structure and may provide enhanced short-term confidence in the capital investment plans being submitted.

1. Introduction

This section provides a discussion of the background, objectives, and scope of the project and an overview of the structure and contents of this report.

1.1 Background

Against a background of aging infrastructure, it is essential that network utilities implement robust asset management practices in order to optimize asset replacement and future operating costs, while providing adequate flexibility for future uncertainty. OEB staff recognizes the need for additional asset replacement expenditure, but believes that customers are best served where such expenditure can be justified on the basis of clear considerations of not just the magnitudes of costs and benefits, but also the stakeholders and individual customer categories (generation vs. load) to which these items will accrue. The importance of adequate asset management processes, systems, and implementation will therefore become increasingly relevant in future years to ensure that uneconomic investments can be avoided without jeopardizing overall network integrity.

In this context, from a regulatory perspective, it should be expected that network utilities have established consistent frameworks for asset management and consequential investment plans to ensure networks continue to be developed in an economic, efficient, sustainable, and secure manner. The development of robust asset management processes and systems by network utilities can provide evidence to regulators (and other organizational stakeholders) regarding the integrity of investment plans. Similarly, the implementation of robust asset management systems can improve the accuracy of resource and capital forecasts, and thus reduce uncertainty in both the network utility's planning processes and in the regulator's assessment and determination of appropriate forward revenue allowances for the utility.

The OEB staff also indicated that it is clear the role and technical features of the electricity distribution infrastructure in Ontario is changing in ways that could fundamentally alter the function and the business of electricity distribution. In particular, systems designed solely to deliver electricity service to customers will increasingly be called upon to accept electric power from customers generating electricity connected to distribution systems either directly or through customer interfaces.

A final complexity in calculating the capital investment required in the network is the recent introduction of the Green Energy and Green Economy Act in Ontario. This Act places further emphasis on the economic and efficient development of energy networks to effectively facilitate the connection and utilization of transmission and distribution connected renewable-sourced generation.

In light of these issues the OEB staff has indicated that they are keen to develop their knowledge and understanding of asset management practices and how they are best applied within network utilities. Furthermore, OEB staff has also indicated they wish to understand

best practice regulatory approaches in relation to review of network utilities' asset management practices and derived investment plans, with reference to regulatory practices in other international markets.

1.2 Objective and Scope of the Assignment

The stated overall objective for the project was to ensure OEB staff are familiar with the principles and objectives of asset management plans and underlying analytic processes, systems and tools, so that investment planning information provided by natural gas or electricity distributors and transmitters in rates and other applications can be better evaluated.

As such, KEMA was tasked under this specific project to provide a report that provides information on the ways in which regulators assess investment plans, identifying the implicit or explicit use of asset management approaches, including principles, processes, inputs and outputs and decision-making criteria and prioritization methods. Specifically, KEMA was asked to:

- 1) Explain the application of asset management principles, objectives, and processes for network utility investment;
- 2) Describe and compare the regulatory approaches and their reference to asset management principles and practices within the processes, methodologies, and instruments used by international network utility regulators in their assessment of capital investment plans; and
- 3) Assess which approaches are suitable for use in Ontario.

1.3 Structure of Document

This Report seeks to address the scope of the assignment as discussed and specified in Section 1.2 above as follows:

Section 2: Provides a description of best practice asset management principles and approaches for network utilities. This section seeks to clearly identify, describe, and explain the relationships among asset management principles, objectives, and processes applicable to network utilities. The section intends to provide the OEB staff with insights into what best practice asset management by network utilities should encompass and be evident under regulatory review.

Section 3: Provides a description of different regulatory methodologies/tools that can be employed by regulators to review asset management practices and consequential investment plans of network utilities. This includes discussion of their relative merits in different contexts; and the extent to which they are adopted by international regulators,

Introduction

including reference to relevant regulators from the selection reviewed in depth by KEMA (*see description of Section 4 and Appendices below*).

Section 4: Provides a comparison and assessment of the regulatory approaches adopted internationally to review asset management practices and consequential investment plans of network utilities; based on extensive review of international regulatory practices for markets in Australia, Germany, Great Britain, New Zealand, the US and Canada. This section seeks to highlight where regulatory assessment approaches reflect adherence to or the use of the asset management principles, objectives, and processes identified in Section 2 and 3 above. It also provides details of the market context (e.g., number and types of utilities found in these markets) in order to provide an understanding of some drivers of differing regulatory approaches.

Section 5: Provides KEMA's summary observations from the detailed review and comparison of international regulatory practices as captured in Section 4, and briefly outlines KEMA's understanding of the market and regulatory context in Ontario. Finally, on the basis of this and preceding Sections 3 and 4, KEMA outlines a number of methods and systems deployed by the regulators internationally for evaluation and review of asset management plans and derived investment plans for the OEB staff to consider if and how these approaches could be adopted in its own overall regulatory approach to reviewing asset management practices and consequential investment plans of network utilities.

Appendices: The Appendices provide extensive material reviewing international regulatory practices for markets in Australia, Germany, Great Britain, New Zealand, US, and Canada encompassing:

- 1) Characteristics of utilities affected;
- 2) Assessment of utility investment plans;
- 3) Regulatory information requirements;
- 4) Explicit asset management requirements;
- 5) Relevant regulatory instruments;

Introduction

- 6) Regulatory guidance to utility companies; and
- 7) Lessons learned and future areas of focus.

Note that the information for each of the international markets highlighted above has been collated and provided in a stand-alone Appendices document to this Report, which has been provided separately to the OEB staff.

2. Asset Management for Network Utilities

This section provides a description of best practice asset management principles and approaches for network utilities (i.e., it seeks to identify clearly, describe and explain the relationships among asset management principles, objectives, and processes applicable to network utilities). The objective of this section is to provide the OEB staff with insights into what best practice asset management by network utilities should be encompassed and demonstrated as part of the regulatory review.

2.1 Importance of Robust Network Utility Asset Management

In developed economies, investments in electricity network infrastructure have occurred over extended periods, typically decades. The design life of the primary assets employed within such networks is typically in the range of 40 – 60 years. Consequently, many network utilities are entering a significant asset renewal phase requiring increases in asset replacement and refurbishment budgets as their aging network infrastructure assets increasingly approach the nominal end of life. Thus, from both the perspective of the network utilities and the regulators which govern them, it is increasingly essential that network utilities implement robust asset management practices in order to optimize asset replacement and future operating costs. The importance of adequate asset management processes, systems, and implementation will become increasingly relevant in future years to ensure that uneconomic investments can be avoided without jeopardizing overall network integrity.

An emerging new factor in asset management and asset replacement thinking is the challenge to promote cost-effective innovation in a regulated context, with particular attention to Smart Grids and the international vision that is emerging for new grid architectures. Smart Grids are a wide topic and beyond the scope of this report to address in detail, but suffice to note here that there is a significant international momentum in this direction and that investment in asset renewal should take cognizance of new opportunities and requirements. This applies to both transmission and distribution systems and a key risk to be avoided is “a 40 year lock-in” to old architectures when undertaking asset renewal.

In order to ensure a consistent approach is adopted for asset management within network utilities, there are opportunities to adopt common frameworks for asset management which can be applied across all network asset groups. Another advantage of adopting such frameworks is the demonstration of commitment to “good industry practice” asset management for the entire organization.

It is therefore appropriate for regulators to seek evidence of asset management competence when assessing investment submissions from network utilities. Such assessments provide assurances that the network utilities understand and have prioritized their investment plans,

that investment requirements are not overstated, and that customer risk exposures are properly considered.

2.2 Asset Management Principles

Fundamentally, asset management is a business approach designed to align the management of asset related expenditure with organizational goals. The objective is to make all infrastructure related decisions according to a single set of stakeholder-driven criteria. The benefit is a set of investment decisions capable of delivering the greatest stakeholder value from the resources available.

The two fundamental principles of asset management are to seek to most effectively manage the business assets in order to optimally meet the requirements of:

- 1) A range of stakeholders (e.g., legislators, regulators, shareholders, customers and staff); and
- 2) The business in the short-term while maintaining sustainability of the business in the long-term.

The key concept is due balance. In the specific context of network utilities, regulators should seek evidence that network utilities develop, maintain, and operate the networks in an economic, efficient, and sustainable manner. In other words, a network utility should maintain the proper balance for each of the following items:

- Asset and network costs;
- Asset and network performance;
- Strategic thinking for the future; or
- Asset and network risk.

In addition, the network utility should balance short-term and long-term dimensions of its investment plans and underlying asset management practices.

2.3 Asset Management Objectives

The key goals or objectives of asset management within network utilities (and any other organizations reliant on physical infrastructure assets for service delivery) are to:

- Balance cost, performance, and risk;
- Align organizational objectives with investment decisions; and
- Create a multi-year asset plan based on rigorous and data-driven processes.

Regulators should thus expect to see network utility asset management processes that select a portfolio of projects that achieve all performance and risk criteria for the least cost, with full consideration of budget constraints, life-cycle analysis, and project uncertainty.

In larger network utilities, it can be helpful for the regulator to categorize asset management activities by asset ownership or asset operation. The asset owner is responsible for setting financial, technical, performance and risk criteria. The asset manager is responsible for translating these criteria into an asset plan and the asset service provider is responsible for executing these decisions and providing feedback on actual cost and performance.

Such categorization enables the regulator to structure and focus its review of different aspects of asset management. It also provides internal business focus: asset owners on strategy, asset managers on planning and budgeting, and asset service providers on operational excellence. The asset owner sets the business values, strategy, and objectives in terms of performance targets, risk tolerance, and budget constraints. The asset manager identifies the best way to achieve these objectives and articulates this in a multi-year asset plan. The asset service provider executes the plan in an efficient manner, and feeds back asset and performance data into the asset management process.

2.4 Asset Management Strategy

At the highest level, a regulator should expect that the corporate organizational objective of managing asset cost, performance, and risk should be stated in documentary form. The means by which these high-level objectives are achieved and are clarified through more specific strategic aims and objectives (outcomes) at the operational level should also be documented. Some of the following generic strategic objectives are those which a regulator might expect to see apply within network utilities.

- Ensure network adequacy (security and capacity);
- Ensure availability and reliability of the system;
- Integrate renewables;
- Accommodate regional or local power flows;
- Optimize lifecycle costs;
- Optimize system performance (e.g., maintain or improve current performance);
- Transparency;
- Long-term and sustainable planning; and
- Short-term resource optimization.

2.5 Asset Management Policy

An asset management policy document is a requirement of any formal asset management standard/framework and should contain information defining the boundaries of the asset management system and the portfolio of assets required to ensure adequate service delivery. Such a document should be readily available for regulatory scrutiny.

2.5.1 Description of the Assets Addressed by the Policy

The first component of the asset management policy should be a description of the organization, the boundaries of the asset management system under consideration and the types of assets employed by the organization. Key parameters for a network company could include:

- Geographic area served;
- Customers (power generation facilities, utility companies, industrial customers, regional transmission operators);
- Loading: demand, load growth and seasonality;
- Energy: energy transmitted per annum;
- Populations served and their relative locations to confirm the fundamental direction of power flows;
- High-level physical asset description (i.e., network length, number of stations, network voltages/pressures, asset age);
- Network topography – geographic and electrical; including interfaces (e.g., interconnections); and
- Role and responsibilities of operator (i.e., asset owner, asset manager, and system operator).

2.5.2 Scope of the Asset Management Policy

The scope of the document will clarify which assets are covered by the asset management policy, their purpose, and any associated mandatory (legal, regulatory, and fiduciary) and self-imposed (e.g., environmental), or formal asset management standard compliance obligations.

To simplify the preparation of the overall asset management policy statement, it can be useful to refer to other asset related policies where these exist. Such policies should be complementary to the asset management policy and should be read in conjunction with the overall policy. Examples of other policies relevant to asset management may include:

- Network planning standards (network capacity and redundancy);
- Design standards (equipment specifications, tower construction, station layouts);
- Lifecycle costing framework;
- Asset replacement policy (e.g., when to replace - before/after failure);
- Construction policies and procedures;
- Outage planning;
- Maintenance policies;
- Asset information management;
- Capital planning; and
- Continuous improvement, review, and audit.

The purpose of the asset management policy is to provide clarity throughout the organization regarding the importance of asset management and corresponding commitment from a senior level within the organization.

2.5.2.1 Consistency with Wider Organizational Policies

Inevitably the asset management policy will also interface with other organizational policies. Therefore, statements regarding the consistency of the asset management policy with other organizational policies can further simplify drafting. Other organizational policies may include:

- Safety;
- Environmental;
- Site and information security;
- Financial controls;
- Personnel (HR); and
- Procurement.

These policies may be consistent with mandatory legal, regulatory and fiduciary obligations or introduce requirements beyond those which are mandatory. Again, where such policies exist, policy drafting can be simplified by cross-referencing the relevant documents to demonstrate existence, availability, and interrelationships.

2.6 Asset Management Organizational Structure, Key Responsibilities and Governance

The asset management policy should state which group within the organization has overall responsibility for asset management. In addition, the key decision-making forums and the associated governance arrangements should be stated (e.g., capital planning, investment approval and prioritization, financial authorization levels). Such governance arrangements may be stated in separate documents; however, evidence of a strong asset management organization should be readily apparent to a regulator.

In order to ensure a cohesive and consistent approach to asset management is developed, it is important to clearly define the roles and responsibilities of the central functions relative to operational departments. For larger distribution and transmission utilities, a potential allocation of responsibilities between corporate and the asset categories is provided in the following two sections.

2.6.1 Corporate Responsibilities

This should be a key check for any regulator. Corporate functions often assume responsibility for establishing the overall (high-level) framework outlining the organization's commitment to "good practice" asset management and it is important for this framework to be agreed/endorsed by key stakeholders across the company to obtain support and commitment.

The corporate function should also be responsible for developing, agreeing and communicating the strategic aims/objectives/goals or desired outcomes for the organization. This does not preclude operational departments from subsequently translating each relevant corporate strategic outcome into more specific strategic objectives.

To ensure risk-based approaches to asset management are developed and implemented it is helpful for the corporate function to specify what is meant by risk management and the key components of a risk assessment framework as discussed further in Section 2.7.2.

2.6.2 Communication

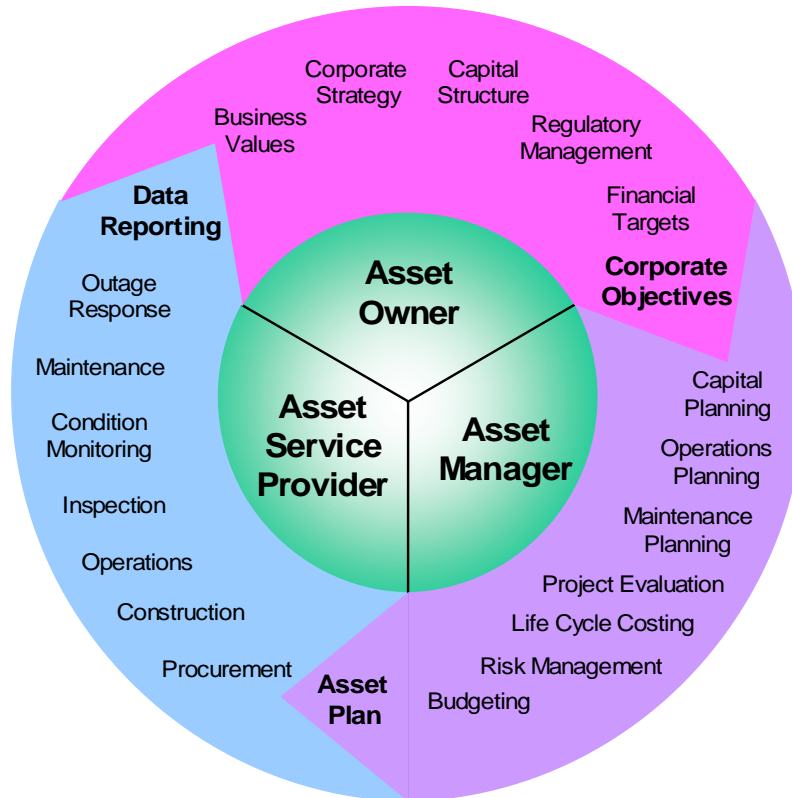
An additional key element of an asset management policy that a regulator should expect to see demonstrated is communication of asset management, policy, strategy, and required practices. Having established an overall organizational commitment to asset management and agreed to a high-level statement of principles at a senior level, it is beneficial to ensure that this commitment is readily accessible and understood throughout the organization. This can be achieved by raising awareness of the asset management framework. In larger organizations, Intranet facilities can be used for this purpose.

2.7 Key Asset Management Processes and Systems

Asset management requires robust processes. Instead of a hierarchical organization where decisions and budgets follow a chain of command and can lead to silos, asset management links, asset owners, asset managers, and asset service providers in a manner that allows investment decisions to be aligned with corporate objectives supported by asset data.

Figure 3 illustrates the continuous nature of the typical asset management activities applicable in network utilities, showing alignment with asset ownership, asset manager, and service provider responsibilities.

Figure 3: Asset Management Activities Relevant to Network Utilities



Asset management processes in network utilities should enable performance, cost, and risks to be optimized. Achieving this balance requires the alignment of corporate goals, management decisions, and technical decisions. It also requires business processes, and information systems to ensure consistent investment decisions based on asset-level data. The result is a multi-year investment plan that maximizes stakeholder value while meeting all performance, cost, and risk constraints.

More detailed discussion of the key aspects of best practice asset management processes and systems that a regulator should expect to see in a network utility with a strong asset management commitment and associated practices is provided in the following sub-sections.

2.7.1 Performance Reporting Frameworks

In order that a comprehensive ongoing understanding of the status of a utility’s activities can be ascertained, it is important to specify targeted and concise reporting requirements. In addition to specifying a required reporting timetable, senior officers should also receive regular updates highlighting any changes to the company risk position, key performance indicators, and investment requirements.

2.7.2 Risk Management

To fully understand asset replacement prioritization, it is important to seek evidence of the risk assessment frameworks adopted by each utility. Such frameworks should include asset-specific risks relating to equipment failure, but also the system risk relating to service delivery to customers. Consequently, it is useful to review asset criticality frameworks where these factors have been implemented. In addition to clarifying investment priorities, such risk frameworks should also address the potential consequences of not investing.

An important dimension of the asset management system is a commitment to identify, measure, monitor, and mitigate the risks impacting the delivery of the strategic outcomes for the assets with respect to:

- Technical performance;
- Safety (to the public and staff);
- Environmental;
- Financial;
- Reputation; and
- Resourcing and skills.

The asset management policy should be linked to the overall risk assessment framework. It should also be stated that the utility is committed to maintaining, developing, and reporting a targeted range of risk metrics throughout the organization. It is important that key risks are collated and understood within the organization. The overall risk position can then be reported on a regular basis. Confirmation is required that the most senior internal stakeholders are regularly updated regarding the key risks impacting the network. Such risk reporting can be simplified by the appointment of a senior officer responsible for risk management. It should also be made clear that risk measures are used to trigger action(s) to address and or manage identified risks for individual assets and asset groups.

The risk assessment framework should state the frequency of reporting, the recipients of risk information and highlight changes and emergent trends. The risk assessment framework should also define how key risks are measured and concisely reported. In addition, the risk management framework should identify how these risk metrics are used and reference contingency arrangements (e.g., emergency procedures) and mitigation techniques.

2.7.3 Asset Replacement Criteria

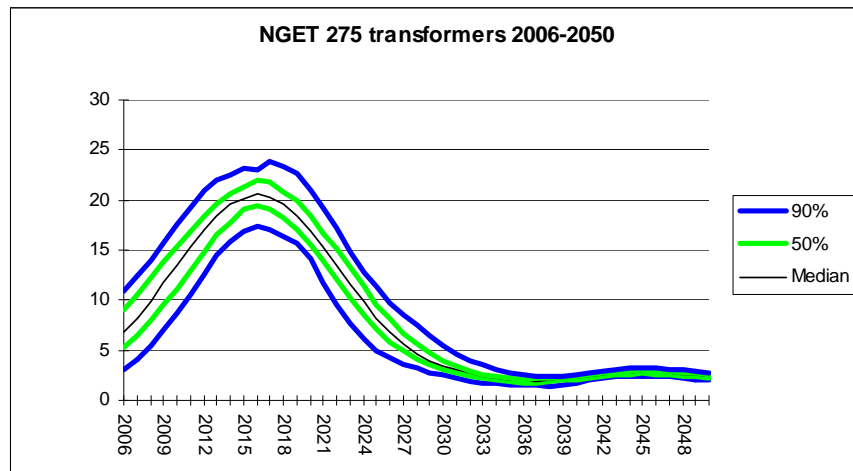
An example of relevant asset management policies and strategies include asset replacement policy. The policy may differ by asset type (e.g., overhead lines, transformers, switchgear, and cables). While it is typical for transmission operators to adopt “replace before failure” policies for key asset categories, differentiated approaches can be more relevant for distribution assets. In addition, it is useful to qualify different policies for the primary asset categories with respect to maintenance, repair, refurbishment, and replacement.

2.7.3.1 Long-Term Asset Replacement Requirements

In order to confirm the scale of asset replacement requirements within particular regulatory timescales, it is important to confirm the utility is planning its asset replacement activities in a long-term sustainable manner to ensure that unforeseen “bow waves” of asset replacement are identified before they occur. This requires a degree of modeling capability to predict future asset replacement volumes, ideally disaggregated to equipment type and subcomponent level.

In order to model future asset replacement volumes, it is essential that the entity maintains accurate information about the assets employed in terms of equipment type, location, year of commissioning, etc. Some more sophisticated asset managers have supplemented their asset registers with additional information such as maintenance and fault history, duty cycles, etc. While these models provide a top-down view of future asset replacement volumes, they alone are usually insufficient for regulatory purposes since they do not provide evidence of which assets require replacement. An example of model output run presents the median, lower, and upper bands of forecast replacement volumes per asset category as shown in Figure 4.

Figure 4: A Typical Asset Replacement Output Model for a Particular Asset Type



The extent to which network utilities rely on the outputs from top-down asset replacement models when formulating future asset replacement and refurbishment forecasts will be dependent on the confidence ascribed to model outputs. While top-down asset replacement forecasting provides useful insights regarding future asset investment requirements, it is essential that model input data reflects the installed asset base as opposed to a generic data set.

2.7.3.2 Asset Condition Assessment

More compelling evidence of asset replacement need is demonstrated by comprehensive and accessible asset condition information tailored to the needs of the primary asset category under consideration. In addition, it is also appropriate to review the utility’s approach to inspections and maintenance. Such asset condition information provides the critical bottom-

up view of asset replacement priorities. The availability and accessibility of accurate asset condition data provides a means to refine and calibrate longer term modeling processes, thus closing the gap between the top-down and bottom-up views. The images below provide examples of asset condition assessments undertaken by KEMA as part of regulatory reviews.

Figure 5: Switchgear - Arrows Indicating Typical Points of Water Ingress

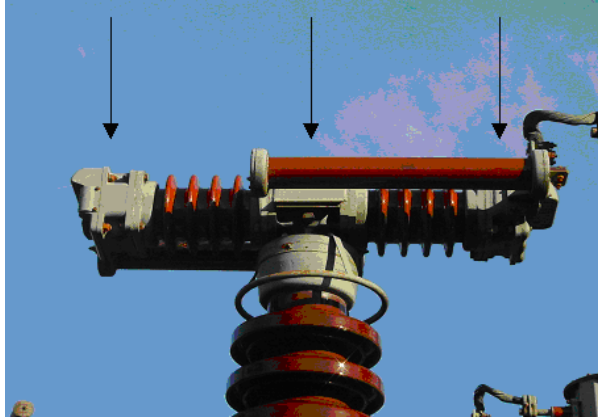


Figure 6: Lattice Overhead Line Steel Tower Corrosion



Figure 7: Deterioration of Overhead Line Steel Tower Foundations



Figure 8: Overhead Line Damper Degradation

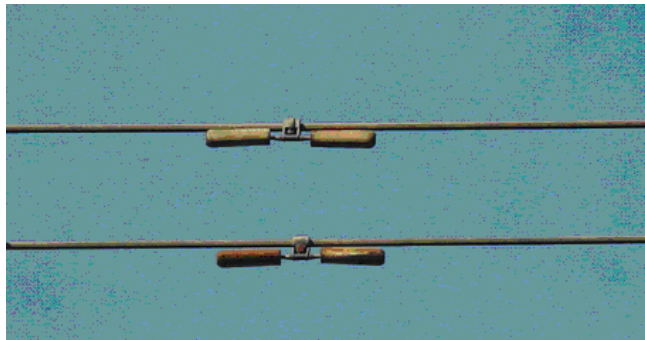


Figure 9: Degradation of Civil Structures within a Switch Yard



Figure 10: Damage to Overhead Line Insulators – Missing Elements

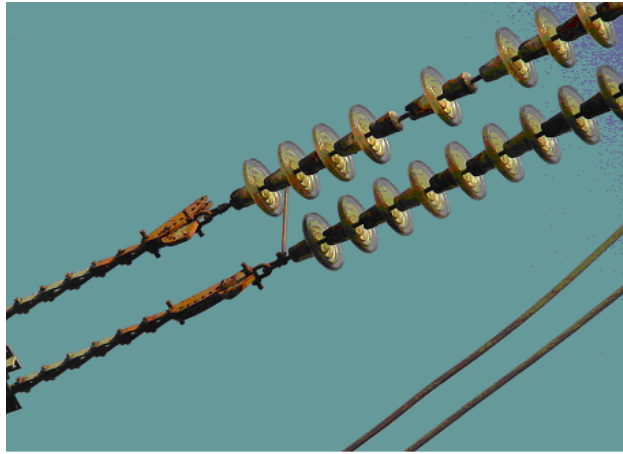


Figure 11: Cracked Insulator Porcelain – 3rd from Bottom



Figure 12: Busbar Clamp Corrosion



Figure 13: Transformer Insulating Oil Leakage



The importance of asset condition data cannot be understated when formulating future capital plans as this information effectively prioritizes short-term investment decisions. However, this information also provides a valuable feedback channel to validate the inputs to longer term replacement models. Consequently, where investment plans are highly reliant on replacement models outputs, it is important to seek assurances regarding the use of asset condition and health information to refine model inputs.

2.7.4 Inspections and Maintenance

Routine inspection and maintenance activities are essential to confirm that hazards are rapidly detected and remedied. Routine inspection and maintenance activities do not usually comprise any detailed asset condition assessment techniques. However, such ongoing activities provide each company with invaluable feedback regarding the overall status of their network. In order to effectively schedule such inspection and maintenance activities, it is fundamental for each utility to develop comprehensive and readily accessible asset register containing details of all the assets employed within their networks. Typical information contained within an asset register would include the type of equipment, manufacturer, design, commissioning date, serial number, and location. Such asset registers can then be utilized to ensure all assets are identified, inspected, potentially linked with work control systems.

In recent years there have been numerous initiatives within electricity distribution and transmission utilities to improve the efficiency of inspection and maintenance activities whereby trained operational staff receive instructions in the field and record their inspection activities via portable devices capable of two way communications with central databases and work scheduling systems. Further sophistication is possible by interfacing asset registers with Geographic Information Systems (GIS) to enable staff to identify particular assets from maps on hand held devices. This feature is particularly useful for tower identification when inspecting overhead lines.

While security and hazard related inspections are typically scheduled on a time based system, there are a variety of options available for maintenance scheduling of varying sophistication. There is increasing scope for maintenance to be based on the number of operations or asset condition for particular asset groups. Obviously, these latter scheduling methodologies have the advantage of maintenance prioritization but also require more proactive asset monitoring.

2.7.5 Capital Planning Processes and Asset Plans

Appropriate capital allocation is essential for robust asset management. Consequently, the process by which potential investments are considered and approved must be developed at a senior level within each organization. Formalized capital allocation processes are critical to the approval of optimized and prioritized asset plans. Key to organizational capital allocation processes will be the authority levels for approvals and associated governance arrangements.

Asset plans are required to enable implementation of the strategic aims and objectives for each organization in alignment with the overarching asset management policy. These plans should include:

- Capital investment plans – covering load and non-load related investments;
- Maintenance plans – covering preventative and corrective maintenance;
- Condition assessment activities – reviewing the condition of individual assets and/or asset groups; and
- Outage planning – covering the overall coordination of network outages to enable asset construction, replacement, maintenance, and condition assessment activities.

2.7.6 Integration of Asset Management and Network Expansion Requirements

During the assessment of electricity distribution and transmission utility investment plans, it is common practice to segregate asset renewal initiatives from network expansion (and reinforcement). The driver for replacement is predominantly deterioration in asset condition over an extended period until the ability of the asset to operate reliably is compromised. Consequently, the prioritization of asset replacement is largely within the control of the utility.

Network reinforcement and expansion requirements are primarily driven by changes in demand and generation profiles on a particular network. Such changes are usually outside the control of the utility and therefore it is important to monitor emergent demand and generation patterns, forecast changes and plan reinforcements and network extensions to accommodate future power flows and exceptional events.

Inevitably, some assets will be nearing the end of their operation lifecycle at the same time that load-related reinforcement or expansion is required. Consequently, it is important for utilities to integrate and prioritize network investment plans for asset replacement and

network reinforcement. In such circumstances, it is important to avoid automatic like-for-like asset replacement, as changes in network usage may merit revisions to network configurations and ratings. Agreement is required between utilities and regulators regarding the consistent classification of load related and asset replacement driven investments.

2.7.7 Refurbishment vs. Replacement [Capital vs. Expense Optimization]

Asset renewal initiatives involve either the replacement of existing assets with new equipment or the refurbishment of existing equipment to extend asset life. In addition, enhanced levels of ongoing asset maintenance can be used as a means to extending the asset lives of network equipment. In such circumstances, a trade-off needs to be made regarding the increased costs of maintenance versus the benefits of deferred asset replacement.

Depending on the type of equipment under consideration, enhanced maintenance regimes can prove more efficient than outright asset replacement. A good example of such a trade-off relates to the painting of overhead line lattice towers where replacements can prove challenging, both operationally and contractually. Asset management systems and policies should therefore provide guidance regarding the pursuit of enhanced maintenance for particular asset categories and critical assets.

Similarly, comparable policy guidance is useful for replacement versus refurbishment decisions. While some asset refurbishment options can be demonstrated to be cost effective for some asset types such as overhead lines, there is a trend towards outright asset replacements for other asset categories such as substation equipment.

2.7.8 Procurement Efficiency

The previous sections have highlighted how robust asset management processes can be used to demonstrate the need for network investment, particularly with respect to asset replacement. However, once the need for asset replacement has been established, it is then important to ensure equipment can be procured and installed cost effectively to optimize the financial materiality of the investment. This requires efficient and sophisticated procurement processes, especially against a background of changing international prices for network equipment and materials. Potential techniques include:

- Consideration of a range of potential engineering solutions;
- Adoption of functional specifications for equipment using internationally recognized standards;
- Consideration of international sourcing of equipment;
- Standardized equipment ratings wherever possible;
- Minimized inventory holdings;
- Maximized buyer power and economies of scale with bulk orders;

- Development of appropriate quality assurance procedures for particular types of network equipment;
- Adoption of lifecycle costing techniques and include operational costs;
- Consideration of implementation complexity and operational flexibility;
- Development of long-term relationships with suppliers; and
- Provision of volume forecasts in advance to suppliers and contractors for future equipment and service requirements.

Forecasted levels of expenditure for both asset replacement and network reinforcements/expansion are dependent on the volume and unit costs of the network equipment to be procured. Once forecasts of asset volumes have been established for asset replacement and network expansion, it is important to multiply these volumes by accurate unit cost information to derive investment forecasts. For regulators it can be particularly informative to benchmark and compare and contrast unit cost data from different network utilities.

2.7.9 Asset Plan Delivery

In order to implement agreed asset plans, distribution and transmission utilities must ensure that suppliers and contractors can be mobilized within the timescales envisaged, that the utility has sufficient resources to adequately manage a series of concurrent network investment projects, and that access can be provided to work on networks without unduly jeopardizing the reliability or security of supply to end customers. The practicalities of delivering the proposed plan within the specified timescales must be addressed for the asset plan to be credible.

2.8 Key Inputs and Outputs in Asset Management Systems

It is useful for regulatory assessments of energy network investment plans to consider the asset management capability and maturity of the organizations submitting proposals. Section 4 (and the Appendices) of this report discuss the extent to which regulators in different jurisdictions utilize asset management information during the approval of investment plans. As discussed in the preceding paragraphs, the key inputs and outputs from asset management systems which can be used to test network investment plans are listed below.

Inputs:

- Organizational strategic objectives;
- Asset replacement policies;
- Demand and generation forecasts – regional and within service area;
- Asset base knowledge from comprehensive asset register(s);
- Asset age data for key asset categories;
- Asset life assumptions;
- Risk management policies and organizational risk tolerance;

- Accessible and accurate asset condition information; and
- Maintenance strategies.

Outputs:

- Optimized Capital Expenditure with Operating Costs (Expense items);
- Structured capital planning processes and investment authorizations;
- Targeted reporting and monitoring frameworks;
- Procurement capability including unit costs; and
- Asset replacement volumes.

2.9 Key Features of Best Practice Network Utility Asset Management

2.9.1 Commitment to Asset Management

Adoption of strong asset management practices within capital intensive infrastructure organizations requires acceptance that asset management should have a high profile within the business, and therefore require a formal commitment by the business. As indicated above, the fundamental objective of the adoption of robust asset management is to optimize performance, costs, and risks relevant to service delivery.

In order to demonstrate this commitment to a regulator, the network utility should evidence a high-level commitment to asset management which is visible across the organization with the supporting rationale. This can be achieved through the development and agreement of a common framework for asset management.

Another visible means of demonstrating organizational commitment to asset management is for a senior corporate officer to be made responsible for asset management across the organization, which ensures asset management considerations are clearly understood during corporate decision-making processes. For example, there could be a Board Director of Asset Management.

2.9.2 Meeting both Legal and Regulatory Obligations

Network businesses have traditionally had a number of mandatory requirements relating to local laws and financial reporting. However, utility organizations have more recently been faced with additional regulatory and environmental requirements both of which have asset management implications.

The act of creating asset management plans will involve documenting the binding obligations to which the organization must comply. While the organization as a whole will have documented all these requirements, they may not have filtered down to those parts of the business responsible for asset management. The process of reiterating the mandatory

requirements, especially those relating to service delivery, safety and the environment, will provide a focus upon which asset management practices need to be developed.

2.9.3 Setting of Clear Strategic Objectives

The strategic outcomes sought by the organization are usually discretionary and provide clarity regarding priorities for network utilities. Consequently, the strategic outcomes sought by each organization should be reiterated in an overall asset management framework document in order to develop delivery focused asset management approaches.

In order to achieve best practice asset management and to align with the requirements of any of the prevailing formal asset managements standards as discussed in Section 2.10, it is important for senior management to set the expectation that all asset management systems will:

- Adopt a long-term outlook;
- Be sustainable; and
- Seek continuous improvement.

A regulator should expect to document evidence of these strategic objectives.

2.9.4 Use of Systematic Approach to Ensure Sustainability

The primary responsibilities of network utilities are to manage their respective asset bases in a sustainable manner over the long-term, while simultaneously delivering the desired strategic objectives for each organization. For example, these responsibilities usually include:

- Developing the asset base to accommodate load growth, new generation sources and regional power flows;
- Prioritized replacement of assets reaching the end of their operational lifecycles;
- Removal of redundant assets;
- Repair and replacement of defective assets;
- Routine maintenance of assets;
- Condition assessing the asset base;
- Analyzing the performance of the asset base;
- Developing asset criticality and risk frameworks;
- Analyzing asset specific and systemic risks to service delivery; and
- Optimizing asset investment priorities.

In order to manage assets in a long-term sustainable manner, a network utility should develop and implement an asset management system to ensure delivery of strategic objectives. From this asset management system, it should be possible to then develop asset plans aligned with organizational planning cycles.

It should be recognized by a regulator that the scale of investment in asset management systems should be proportionate for each organization. The structure, level of formality, and requirements to develop comprehensive IT systems should be linked to organizational size. In the larger network utilities it is unlikely that any single individual will have sufficient knowledge to optimize investment decisions across the entire asset base and therefore robust processes and systems are required. Such requirements are usually less significant in smaller utilities, although some procedural and information formality is necessary to ensure that the experience and knowledge of key personnel is shared and to avoid a short-term loss of “corporate memory”.

The requirements of asset management systems also vary between transmission and distribution network utilities. The asset bases of transmission utilities typically comprise relatively small numbers of high value individual assets which are proactively managed according to a “replace before failure” policy. Distribution utilities are typically characterized by much greater populations of lower value assets, many of which are managed according to a “replace on failure” policy.

2.9.5 Use of Risk-Based Approach

Inevitably, there will be a number of risks which could undermine delivery of organizational strategic objectives. Consequently, it is important that risk-based approaches to asset management are adopted to ensure risks are recognized and can be mitigated. As part of the overall framework for asset management in the larger network companies, regulators should expect to see evidence that senior management ensure that comprehensive risk-based elements are included within the overall asset management system. The rationale for a formalized and systematic approach to risk assessment in the larger utilities relates to the size and geographic spread of the asset base where it would be impossible for individuals to be familiar all the risks facing the organization. Key dimensions of any risk-based approaches that a regulator should expect to see within network utilities with strong asset management practices are:

- **Identification:** Risks should be related to the (non) delivery of strategic outcomes;
- **Prioritization:** Ideally the hierarchy of the identified risks should be established to clarify asset category priorities;
- **Measurement:** Identification of appropriate metrics to provide insights regarding the status of each risk;
- **Monitoring:** Once measurement techniques have been established for specific risks, a routine program of monitoring should be undertaken in order

to understand the current risk position, but equally important, any emergent trends;

- **Mitigation techniques:** Having identified the key risks relevant to a specific Asset Category, it is important to plan how such risks can be mitigated and what (if any) contingency measures are required, e.g., strategic spares; and
- **Reporting:** Having established a monitoring framework for the key organizational risks relevant to each Asset Category, it is important that this information is then communicated to senior stakeholders within the asset category and the corporate function.

Risk-based approaches can be enhanced by the adoption of asset criticality frameworks which identify groups of assets key to service delivery.

2.9.6 Conducting Ongoing Review of Performance

In order to develop closed loop asset management systems which facilitate continuous improvement, the overall framework for asset management should explicitly state that all asset management systems should be subject to regular review. This ongoing review of asset management systems and consequential asset management performance should be clearly evident to a regulator.

Review processes can be internal or external to the organization. Internal review processes should be formalized, coordinated, and involve the expert practitioners. An example of an external review technique capable of enhancing asset management understanding is benchmarking with organizations with similar service obligations.

A further means of review available to an organization is audit. Once an asset management system has been implemented, it will be possible for audits to be undertaken to ensure practices continue to be aligned with policy and objectives (i.e., to ensure the asset management system is being operated as prescribed). Where such systems are formally certified, as there is an ongoing dimension (typically biannual review) to any formal asset management certification, it is usual to expect a commitment to internal controls and audit activities to confirm policy and practice align.

2.10 Existing Formal Frameworks for Best Practice Asset Management in Network Utilities

Frameworks to formalize and enhance asset management capabilities and practices have been developed and implemented in a number of international jurisdictions. In this section, a high-level overview is provided for PAS 55, which originated from the UK, the Total Asset Management Manual from Australia, and the International Infrastructure Management Manual from New Zealand, which is also widely recognized in Australia and the US.

2.10.1 BSI – “Publicly Available Specification” PAS 55

Over the past 10 years, a framework for infrastructure asset management has been developed and implemented under the auspices of the British Standards Institute (BSI). This resulted in the publication in 2004 of a “Specification for the optimized management of physical infrastructure assets” introduced as Publicly Available Specification (PAS) 55: 2004. An updated version of this specification was released in November 2008.

PAS 55 has been developed as a reference document for asset management by an international group of infrastructure owners, operators, and consultants in the electricity, gas, water, rail, brewing and mining sectors. In the short time frame of its existence the PAS 55 asset management framework has been adopted by a broad range of utility companies operating in multiple jurisdictions including the US, UK, Netherlands and Hong Kong.

PAS 55 is split into two parts:

- **Part 1** – Specification for the optimized management of physical infrastructure assets: this part contains the requirements or the need for standards. These requirements form the basis for any assessment of conformance (internal or external) and subsequent certification.
- **Part 2** – Guidelines for the application of PAS 55-1: This part provides guidance to aid the understanding of the intent of the requirements in Part 1 and guidelines for implementation.

PAS 55 provides a common framework across 21 dimensions of good asset management practice, from lifecycle strategy to routine maintenance (encompassing cost, risk, and performance). It also addresses the entire asset lifecycle: from asset need identification to design, acquisition, construction, commissioning, utilization or operation, maintenance, renewal, modification and ultimate disposal.

Over the past three years, the majority of electricity and gas network utilities in Great Britain have developed and certified their asset management systems in accordance with PAS 55. This has largely been achieved as a result of a requirement from the regulator to demonstrate competence in asset management. While PAS 55 is not a mandatory requirement for British network utilities, there is a strong implicit expectation from the regulator for utility certification.

2.10.2 International Infrastructure Management Manual

The International Infrastructure Management Manual originates from New Zealand but is recognized and has been implemented in Australia and the US. It is divided into five sections dealing with the following aspects of asset management:

- 1) The first section focuses on the importance and requirement for formalized asset management; it provides a high level view of asset management planning.
- 2) The second section relates to the implementation of asset management frameworks involving organizational structure, corporate objectives, preparing and using asset management plans, service delivery issues, and review and audit procedures.
- 3) The third section deals with asset management techniques relating to levels of service, demand forecasting and management, condition assessment and performance monitoring, optimized decision making, risk management, maintenance management, valuations and financial forecasting.
- 4) The fourth section deals with asset management systems and data management. It details the role of IT in efficient asset management and various data collection point for assessment.
- 5) The final section provides a summary of issues at country level for Australia and New Zealand.

2.10.3 Total Asset Management Manual

The Total Asset Management (TAM) Manual relates to the strategic management of physical assets to best support the delivery of services in government agencies. The TAM Manual consists of three sections:

- 1) The Introduction explains how Total Asset Management fits within overall organizational strategy.
- 2) The TAM Overview includes guidelines to develop five plans which comprise the Total Asset Management Strategy. Various Australian government departments and agencies are required to prepare an Asset Strategy in support of funding submissions or to receive regulated returns on investment. These strategic plans contain guidelines for:
 - a) The primary Asset Strategy which addresses high-level asset planning, including whether assets should be acquired, upgraded, maintained, or disposed of;
 - b) The Capital Investment Strategic Plan which explains how new assets will be acquired or existing assets upgraded;
 - c) The Asset Maintenance Strategic Plan which gives a structured process for planning the maintenance of existing assets;

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- d) The Asset Disposal Strategic Plan which identifies assets that are surplus to requirements and how the disposal process will be managed; and
 - e) The Office Accommodation Strategy that is an Asset Strategy restricted to Office Accommodation assets only. Its purpose is to capture the benefits of a whole-of-government approach to the management of office accommodation.
- 3) The Assessment & Decision Tools section provides a set of tools to develop and implement a methodology for addressing concerns of other indirect stakeholders involved, including:
- a) Sustainable Development;
 - b) Heritage Assets;
 - c) Demand Management;
 - d) Life - Cycle Costing;
 - e) Economic Appraisal (which includes a link to other Treasury documents);
 - f) Value Management;
 - g) Risk Management;
 - h) Post Implementation Review;
 - i) Performance Evaluation;
 - j) Asset Information; and
 - k) Private Sector Participation (which includes a link to other Treasury Documents).

3. Assessment Approaches, Methodologies and Tools Available to Regulators

This section outlines a number of assessment approaches, methodologies, and tools that regulators can apply in their review of network utility investment plans and the broader asset management practices which network utilities employ. These are listed below:

- Ex-ante assessment;
- Ex-post review;
- Expert third party review;
- Review of policy vs. practice;
- Multi-year settlements;
- Reporting and monitoring;
- Triggers for regulatory intervention;
- Incentivization;
- Comparative benchmarking; and
- Use of output measures.

The above list is methodologies/tools which are used and deemed appropriate by different regulators to deliver regulatory effectiveness in the context of their relevant jurisdictions and governance frameworks. It should be noted that a regulator may choose to apply a number of these approaches in determining an appropriate regulatory control. Thus, each of the above regulatory approaches, methodologies and tools are briefly discussed below with an assessment of their relative merits. In addition, we indicate their use by regulators internationally and the context of their application.

The final part of this section provides an overview of the relative importance and value of the ten regulatory approaches, methodologies, and tools - discussing which are fundamental and/or widely applied and which are more optional and/or less widely applied (noting that this latter category may reflect leading practice).

3.1 Ex-Ante Assessment

Ex-ante assessment is the principal building block of regulation of network utility investment plans, and may also include consideration of asset management practices. It is utilized by regulators in energy markets worldwide.

Essentially, network utilities are required to submit their planned investment forecasts with supporting information prior to being granted funds to undertake these investments. This approach can take two forms:

- 1) Ex-ante review of full multi-year investment plan program and setting of overall revenue allowances to enable this plan and reasonable changes to this plan over time to be delivered (i.e., plan “churn” arising from some scheme

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no longer being required but others emerging) – this is the more typical practice adopted in Australia, Germany, Great Britain and the US for example; or

- 2) Ex-ante review of individual schemes either on an annual review basis or as they arise - this has been the case for some transmission investment in New Zealand, Singapore, and some US jurisdictions, but requires intensive regulatory engagement.

The benefit of ex-ante assessment is that it gives the regulators scrutiny and control of network utility investments before monies and assets have been committed. This means that customers have some assurance that they are only paying for investments which are truly required and are implemented in the most effective and cost efficient manner.

The fundamental disadvantage of ex-ante assessment is that it relies on forecasts of both the market environment and network issues such as level and location of connecting generation and load. The level of uncertainty over the assumptions and derived position of the regulatory approval will increase with the time period of the forecast. Consequently, since the advent of advanced energy markets and the regulation of constituent network utilities, regulators have sought to introduce measures which give greater confidence in the robustness of their ex-ante assessments. For example:

- 1) Link elements of revenue allowances to perceived investment and cost drivers (e.g. no. of new connections; cost of raw materials);
- 2) Incentivize forecast accuracy by the network utilities;
- 3) Detailed review of outturn investment against predicted investment for preceding regulatory period;
- 4) Detailed review of underlying asset management and associated investment planning processes;
- 5) Require reporting of actual investments to enable monitoring of investment performance;
- 6) Measures which provide scope for retrieval of inefficient or under-spend of investment allowances; and most recently; and
- 7) Link investment to specific deliverables/output measures of network capability, condition, performance, and risk.

A number of these aspects are outlined in more detail in the following sections.

Despite its drawbacks in an increasingly complex energy market within which network utilities have to operate, ex-ante assessments are an essential methodology, which in practice all regulators use as a major part of their work. Thus, despite the divergent approaches to network utility regulation and differences of emphasis on review of asset management practices, ex-ante assessment is a common feature of all of the regulators KEMA reviewed in Section 4 (and Appendices).

3.2 Ex-Post Review

Full ex-post review provides the regulator with the ultimate certainty that the network utilities only receive the appropriate funding. This reflects actual investments made subject to these being efficiently incurred and means that policies resulting in under-spend to derive super profit or higher than desired returns on capital cannot be pursued as a strategy by network utilities.

The benefit of a full ex-post review is that customers are seemingly assured of being charged only for effective and efficient network investment as network utilities are unable to “beat the regulator” based on information asymmetry or negotiating skill. For investments relating to load growth, network reinforcements and expansion, the ex-post approach can be useful to assess retrospectively the need case and efficiency of the committed expenditure.

The disadvantage of a full ex-post review is that it provides high regulatory uncertainty to the network utilities. This is particularly important to privately owned companies with shareholders as such regulatory uncertainty can create high costs of capital due to the fear of stranded and/or unrewarded assets. There are also potential perverse incentives for network utilities to over-invest if they can successfully negotiate a high revenue allowance and then convince the regulator the underlying investment plan which they implemented was actually reasonable. This allows the network utility to maximize the size of their asset base and thus regulated revenues.

For investments relating to asset replacement, the ex-post approach is less useful for the retrospective assessment of committed expenditure. This is largely because the replaced assets have already been removed from the system (and usually disposed of), thus minimizing opportunities for the regulator to confirm (or challenge) the validity of the investment requirement.

Due to the strong disadvantages in a privatized energy market of pursuing a full ex-post review approach this practice is not relied upon in any of the international markets reviewed. However, for some markets where the network utilities are large and regulatory periods for which investment allowances are set are long, then regulators have sought to introduce an element of ex-post review to prevent excesses of inflated forecasts or over-investment. This can be done in two ways:

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- 1) **Mechanistic** – this is where a formulaic adjustment is made based on the level of investment seen against that forecast when ex-ante assessed allowances were set. The typical form is that under-investment leads to the network utility only retaining a proportion of the avoided costs of investment (this partly aims to recognize some of the under-investment may be due to development and achievement of investment efficiencies) and vice versa where the network utility over-spend, it is only exposed to a proportion of the costs (recognizing this may be due to events outside the control of the network utility, but also to prevent excess investment by allocating some of these costs to them).
- 2) **Assessment** – this involves the regulator or commissioned third party experts reviewing the outturn investments made by the network utility and assessing the merits of the requirement for those investments and the efficiency of the investments. Based on this assessment the regulator then determines whether to allow all, part or none of specific investments to be included in the regulatory asset base and/or receive forward regulated revenue returns.

A mechanistic approach is simple to establish, but creating the appropriate incentives aligned with regulatory objectives can be difficult, especially if there is interaction with other incentive and index mechanisms. It can also be seen to create a “tipping point” and a formula for the network utility to use in determining whether or not to invest, regardless of effectiveness or efficiency of spend. It therefore runs the risk of encouraging perverse behavior by network utilities by immunizing them from post-assessment based regulatory intervention.

An assessment based approach has the benefit of regulatory staff being able to review unfettered the outturn investments of the network utility, how these relate to the ex-ante forecasts and what changes in circumstances arose. However, the disadvantage is it requires expert review and the regulator may suffer from information asymmetry or expertise asymmetry in being able to make the assessment effectively. In addition, in jurisdictions requiring the regulation of many network utilities, the assessment burden on regulators can become too high or disproportionate. There is also a risk for the network utility that a lack of understanding or other factors could lead to disallowance of perfectly legitimate expenditure.

Most regulators which adopt ex-post review (whether to a greater or lesser degree) prefer to adopt an assessment based approach given the balance of risks, especially where materiality is high and the governing revenue control framework for the network utilities is complex.

Regulators most interested in reviewing the robustness of network utility asset management and derived investments in practice versus their ex-ante predictions/submissions for revenue controls, employ ex-post reviews of one form or another. This is evident in Australia (Section 4.1.1), Great Britain (Section 4.4.3), and the US (Section 4.4.5).

3.3 Expert Third Party Review

The earlier analysis noted that there is often an asymmetry of both information and expertise between the regulatory staff and the staff at the network utility. While it is possible that the “balance of power” lies with the regulator in the case of very small utilities more typically the reverse is the case and is particularly evident for the largest utilities.

In the cases where this balance of power resides with the utilities, this can lead to regulatory staff being unable to effectively determine the appropriate investments that a utility should make, and whether supporting asset management practices are effective or otherwise. While views from other market participants and stakeholders can act as a counter balance and help the regulator in these situations, these views are often tainted by either “lobbying perspectives” or “commercial strategies” of individual stakeholders. Consequently, in this situation the use of third party experts is a very strong tool which the regulator can employ to seek to redress the balance of power.

The application of third party experts by any particular regulator will depend on the size and knowledge base/skills mix of the regulatory staff. However, some examples of where regulators have used third party experts are:

- 1) Review of asset management processes;
- 2) Review of related asset planning, procurement and construction processes;
- 3) Site visits to conduct condition and/or risk assessment of specific assets;
- 4) Support in review of submitted data and supporting commentaries (i.e., justifications) within Price/Rates Reviews; and
- 5) To provide peer and/or international comparator benchmarking.

The benefits of expert third party support is that the regulator can access specialist expertise and knowledge which they do not have internally, utilize levels of resources they would not otherwise be able to deploy, and can access information and knowledge of the network utilities in their market and comparator utilities internationally. They can also use third parties as expert challengers enabling the regulator to act as broker and choose whether to take some or all of the third party views into account when making their regulatory determination.

The disadvantages of employing third party experts is limited, but risks to the regulator can arise from lack of transfer of knowledge and understanding from third party experts to the regulatory staff, or subsequent use of knowledge by third party experts to the benefit of network utilities (though this can also be positive where the rigor of utility forecasting is improved).

In practice, all regulators who engage in rigorous and extended review of network utility investment plans and underlying asset management practices employ third party experts to a greater or lesser degree depending on the number, expertise, experience and knowledge of the regulatory staff. This is particularly evident in Australia (Section 4.4.1), Great Britain (Section 4.4.3), and to a degree, in some of the US markets (Section 4.4.5).

3.4 Review of Policy vs. Practice

In the early years of regulation of network utilities, regulators typically focused on the quality of policies that network utilities have in place to provide them with reassurance regarding the network investment plans they put forward for approval. As regulators have gained more expertise and understanding and with growing importance of aging network issues, there has been increasing focus on actual practices of the network utilities.

Review of network utility policies versus network utility practices is a powerful tool for examining the true commitment and application of network utilities to effectively deliver robust asset management practices throughout their organization. Thus, there is now increasing review of the consistency of company policy with company practice (i.e., do network utilities actually do what they say they do in the field).

The only real disadvantage of this approach is the high assessment burden it places on the regulator and thus much of this scrutiny is supported/undertaken by third party experts who can apply expert resources in a concerted manner over a period of time to explore the key facets of asset management practices and how they adhere to company asset management policies. This can be a time consuming exercise. Where there are large numbers of utilities to review, this would present a real challenge to fully apply such a rigorous review approach for every utility, and as such its application should be guided by the materiality of costs in the investment plans relating to asset replacement to ensure the level of regulatory scrutiny remains proportionate.

This approach is only fully applied by a few regulators who face rapidly increasing investment requirements from network utilities for asset replacement. Consequently, given these issues are particularly pressing in the Great Britain market, and the materiality of the investments are large and increasing by orders of magnitude (e.g., three-fold from current to forthcoming regulatory period for electricity distribution), the Great Britain regulator is the first to extensively review network utility asset management practices on the ground and their adherence to stated asset management policies. Thus, this approach is principally applied in Great Britain (Section 4.4.3, but also beginning to emerge in Australia (Section 4.4.1).

3.5 Periodic Cyclical Multi-Year Settlements

Regulators have the option to choose to assess/review network utility investment plans on a frequent, infrequent, or ad hoc basis.

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Frequent review helps to reduce forecast risks leading to large deviations from expectations, reduces information asymmetry advantages for the network utility leading to poor “deals” for the customer, and maintains regulatory knowledge and understanding of network utility practices. However, frequent review requires intensive resourcing or shallow assessment to be able to implement, especially for markets with very large or very numerous utilities. In addition, it typically does not fit with the investment lead times, commissioning timeframes and certainty of income required by network utilities. Consequently, frequent review is not a practical option – although it is used for system operators where activities are less investment oriented and are subject to highly changeable market circumstances year after year.

Another disadvantage of frequent reviews is that it can encourage the adoption of short-term time horizons and a lack of long-term management vision in what are essentially long-term businesses. A further risk for regulators in such situations is that they can become the proxy decision maker rather than the utility’s management team regarding the need for key long-term investments and increase the regulator’s exposure to criticism in situations where operational problems occur.

Infrequent review (i.e., multi-year settlements) enables capture of network utilities’ investment lead times and commissioning timeframes. The review also enables regulators to conduct comprehensive, detailed, and thorough assessments on network utility investment plans and, where reviewed, asset management practices. While they are exposed to the disadvantages and risks as outlined above for ex-ante assessments, these risks can be mitigated to a greater or lesser degree by various measures that the regulator can employ at the time of establishing the multi-year settlement and in structuring the multi-year settlement.

Ad hoc review is useful to minimize the burden of review faced by the regulator, especially where they are responsible for a large number of network utilities or where asset management and/or consequential network investments are either immaterial issues or largely predictable/stable in nature. However, the major disadvantage is that the regulator has very little oversight or control over the actions of network utilities, unless those network utilities trigger an ad hoc review (typically by requiring material additional revenues – materially higher tariffs to be applied to customers or possibly through material non-performance in some manner). Hence, there is potential for not identifying and removing enduring inefficiencies and performance issues.

Consequently, nearly all regulators apply a periodic cyclical multi-year settlement approach for regulatory review of network utility investment plans and these are typically five year periods which are deemed to strike the appropriate balance of investment certainty versus forecast risk. Despite the varied regulatory frameworks internationally, it is only the US markets (Section 4.4.5) which do not apply a cyclical multi-year review of network utilities which is used by Australia (Section 4.4.1), Germany (Section 4.4.2), Great Britain (Section 4.4.3), and New Zealand (Section 4.4.4).

3.6 Reporting and Monitoring

In addition to periodic assessment, regulators can implement associated reporting and monitoring processes which bridge these periodic assessments. Such reporting and monitoring processes have steadily been introduced, expanded in scope, and increased in depth over time by regulators in established markets as they have seen the market context within which the network utilities operate become increasingly complex and uncertain.

As such, reporting and monitoring structures, which are typically implemented as annual processes, have become an increasingly important part of regulators' approaches to review network utility investment plan deliveries and the outcome of asset management practices.

Initially such reporting and monitoring can focus on key measures of performance such as customer service, quality of supply (outages, frequency, voltage) and expenditure (tracking of actual vs. forecast data). However, as regulatory objectives become more sophisticated and external circumstances change, other aspects such as environmental performance (energy losses, gaseous and fluid leakage, CO₂ etc) are introduced.

The key purpose and benefit of these reporting and monitoring frameworks is to enable the regulator to review the ongoing activities and performance of the network utilities to verify that these align with expectations and forecasts. Another benefit is that such a framework helps smooth the periodic review processes by generally avoiding surprises and repeat learning by regulatory staff of network utilities and their activities. Such reporting also provides greater transparency to wider stakeholders and this can facilitate their participation in regulatory review processes and/or help regulators assess the merits of network utility activities and plans. Standardized reporting and monitoring processes also impose less regulatory intrusion on network utilities and a more limited burden on regulatory staff than more frequent active regulatory intervention in network utility activities.

The only disadvantage that may arise is where substantial reporting and monitoring requirements are imposed, which add little insight to the regulator and/or impose a high administrative burden on the network utility. However, this is an outcome of ill considered application of reporting and monitoring rather than the principle itself.

Consequently, detailed annual reporting and monitoring frameworks – which are scaled to fit the nature of the utilities being monitored – is prevalent in many international markets. Within the markets KEMA has reviewed for the OEB staff, the principal exponents are Australia (Section 4.4.1), Great Britain (Section 4.4.3), New Zealand (Section 4.4.4), and the US (Section 4.4.5).

3.7 Triggers for Regulatory Intervention

Triggers for regulatory intervention are utilized where regulators are exposed to forecast risk and/or uncertainty of key factors which determine a regulatory settlement and/or the outcome

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investment needs. Such triggers are pre-determined/agreed at the time of regulatory settlement and can be set mechanistically or related to key events or performance thresholds. Furthermore, these triggers can be activated by:

- 1) Regulatory review of data in reporting and monitoring mechanisms;
- 2) Automatic instigation following breach of defined thresholds;
- 3) Network utility initiated requests;
- 4) Stakeholder initiated requests; or
- 5) Occurrence of exceptional unforeseen events.

Triggers can lead to provision of additional funds to network utilities (e.g., to accommodate an unforeseen large scale of connections) or penalization of network utilities (e.g., for failure to spend a minimum proportion of granted capital investment funds).

The benefits of triggers are that they provide either: a) a means for reducing regulatory risk for a network utility without unduly committing to a cost burden for the customers; or b) a means for protecting customers from poor network utility performance and thus incentivizing network utilities to act/invest appropriately.

The disadvantages of triggers are that while the trigger events/thresholds may be relatively simple to define in principle, they can sometimes be harder to verify in practice (e.g., have unit costs truly increased beyond control or has it been the consequence of poor procurement practices). This can lead to a high regulatory burden to determine: a) the veracity of the trigger events – especially where it is the network utility or a stakeholder activating it; b) the impact of the trigger events and thus; c) the consequential financial adjustments required. In addition, they can create a high-level of uncertainty for customers on charges and for utilities on risk exposure. This creates “regulatory uncertainty” which is undesirable for both the network utility and the regulator.

Regulators internationally (and across utility sectors) are split on the merits of triggers, especially where these are mechanistic. Currently within the electricity and gas regulatory communities, swayed by the arguments regarding disadvantages, triggers are not viewed as attractive except for extreme circumstances (e.g., where it is clear a network utility cannot fund its investments to the extent security of supply is at risk), or major events, which while uncertain, have an impact of which can be relatively easily quantified (e.g., the impact of a large number of potential generation connections in a localized area which distorts underlying investment requirements).

Of the regulators KEMA reviewed for the OEB staff, Great Britain (Section 4.4.3) and Australia (Section 4.4.1) potentially see triggers applied by the regulator in extreme circumstances. US regulations (Section 4.4.5) see triggers as either initiation of a rate review

(where utilities are required to submit rate cases for significant changes in tariffs to customers) or special reviews (e.g., ex-post review based on a threshold being breached).

3.8 Comparative Benchmarking

In jurisdictions where there are multiple different utilities providing similar services to customers, the adoption of benchmarking techniques is a highly useful tool for comparing operating costs, capital forecasts and network performance. Benchmarking techniques are reliant on standardized data formats, otherwise considerable time and effort may need to be spent on data normalization.

Once standardized data is made available to the regulator by the relevant utilities, comparisons can be drawn to identify the organizations with outlying metrics relative to their peers. Such outliers can then be used as a prompt for a more detailed investigation to determine whether there are particular business considerations influencing the reported performance or costs.

By creating league tables of the different utility reported characteristics, regulators are quickly able to identify those companies operating at or near the efficiency frontier. It is useful to identify those utilities with the upper and lower quartiles for each metric as this provides a further means of identifying effective business processes which can be used to drive performance improvement and efficiency within a sector. Such approaches often create peer comparison driven change, especially for large privately owned utilities that are competing with each other for both shareholders and investors.

Comparative benchmarking can be further expanded to include international comparator network utilities – but this requires careful normalization of contextual factors which may derive misleading benchmarking results (e.g., climate, geography, network topography, and legislative requirements). Nevertheless, with sound understanding of the comparators and suitable normalization such benchmarking can derive powerful results.

Finally, some regulators also seek to benchmark the more generic functions of network utilities to those of other companies typically of comparable scale in different industry sectors. Though not really applicable to network utility investment plans (except perhaps in the procurement aspect) it can be applied in asset management practices where similar issues are faced and similar practices are required in industries such as rail, aviation, nuclear and defense – leading to some interesting insights.

Typical aspects of network utility investment plans and the underlying asset management practices which drive these investment plans can be benchmarked on a quantitative or qualitative basis include:

- 1) Relative capital expenditures normalized against asset base or number of customers – this can be done at aggregate level for non-load related capital

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costs by category of spend (e.g., asset replacements), or it can be further disaggregated by major asset category, reduction of fault level, operational IT and telecoms, etc.;

- 2) Unit costs – this requires an understanding of the operating expense / capital expense treatment of individual network utilities and the component cost elements within these unit costs;
- 3) Volumes of replacement versus asset population – normalized against asset types and ages. This can indicate both under or over investment; and relative emphasis on engineering operating expense activities;
- 4) Connection costs per type of customer connected (e.g., different demand customers, different types of generation);
- 5) Operating expenses in proportion to asset base – this can be a key explanatory factor in deteriorating asset/network condition, performance and risk;
- 6) Robustness of investment planning processes – how thorough is initial identification of need; what degree of options are considered, how are cost/benefits of different options assessed; how stable are the developed investment plans over time; how accurate are scheme cost forecasts; what post-event actions are taken to continually improve process, etc.;
- 7) Robustness of asset management processes – what systems are in place; what level of documentation; how well are they implemented in practice, etc.;
- 8) Engineering related procurement activities – this can discover comparative efficiencies in asset purchases, for example;
- 9) Capital spend versus forecast and/or allowance – this can indicate relative effectiveness (or accuracy) of network utility forecasts;
- 10) Actual return on capital – this applies where spending and volume of assets vary from the basis used to determine the regulatory revenue settlement;
- 11) Customer performance (e.g., Customer Incidents, Customer Minutes Lost, average service to Worst Served Customers, response time to customer calls, timeliness of completion of customer related activities); and
- 12) Quality of network performance (e.g., availability of the network; number of unplanned outages; frequency and voltage performance).

Benchmarking has the benefit of providing transparency of performance amongst the network utilities and wider stakeholders, and thus, can act as an educator and informer. This is particularly relevant to smaller parties (utilities and stakeholders) who are perhaps less sophisticated than larger parties and can help drive improvements in performance of smaller network utilities. Care does have to be taken with some benchmarking activities to respect commercial confidentialities (e.g., in comparison of unit costs).

Benchmarking also has the benefit of acting as a facilitator of peer pressure. This is particularly effective where the regulated network utilities are privately owned and thus exposed to shareholder scrutiny. As such, the company reputation and comparison with peers are important (and have financial consequences), which motivates network utility executives to seek to be above-average or leading-performer. It could also be important with publicly owned companies where profit may not be a key objective, but strong technical performance relative to costs may be highly regarded by peers.

Consequently, comparative benchmarking is a powerful methodology available to regulators, which is often under-utilized due to uncoordinated individual reviews, or lack of strong focus on comparative performance - especially in asset management. Regulators who have employed this methodology have gained strong insights into network utilities' practices across the peer group within their own market, but also with comparable international peers and other industry sectors.

Most international regulators now use benchmarking to some degree with additional benefit gained from experience of application allowing greater knowledge of efficient and effective network utility performance. Of those countries KEMA reviewed in detail for the OEB staff, such benchmarking is evident in Australia (Section 4.4.1), Great Britain (Section 4.4.3), New Zealand (Section 4.4.4), and the US (Section 4.4.5). It is not applied in review of asset management practices as yet in Germany.

3.9 Incentivization

Incentivization is another aspect of regulation which has been increasingly employed by regulators as they have understood the impact of network utility actions on stakeholders and have identified clear regulatory objectives which they wished network utilities to comply with in the interests of customers and other stakeholders. Areas which regulators have applied incentives include:

- 1) Efficiency of both operating and capital expenditures;
- 2) Security and quality of supply;
- 3) Customer service;
- 4) Environmental performance;

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- 5) Network innovation;
- 6) Generation connections; and
- 7) Forecast accuracy.

Incentivization has been used by regulators to gradually supplement the broader approaches to utility regulation, such as ex-ante reviews. Incentivization can be introduced sequentially to influence desired future behaviors through the use of reward and penalty mechanisms usually impacting utility revenues and profits (and indirectly rates). Incentives can be enduring in nature, or short-term to be removed once a particular objective has been achieved. The Great Britain regulatory framework has progressively increased levels of incentivization, and the regulated utilities have demonstrated an ability to respond rapidly to the new regulatory challenges. Positive incentives have been effectively used in the US market to reward utilities for infrastructure investments that achieve federal objectives (e.g., FERC “candy” to build out the transmission grid).

A key feature of any incentive arrangement is the method by which targets and incentives are determined. In order to establish new incentive mechanisms, it is important to clearly define the information requirements upon which the incentives will be based. In instances where many utilities are affected, consistency of reporting is also required. Consequently, some incentive arrangements have been implemented as reporting frameworks where the incentive and penalty rates have initially been set to zero. Only after confirmation of consistent measurement of the relevant metrics relative to targets are the incentives and penalties then applied. It is important to note the requirement for reporting frameworks to be auditable where incentive mechanisms are introduced due to the financial materiality of revenue adjustments.

A key challenge for regulators is to determine the relative strength of the incentive mechanism. This is usually linked to the amount of utility income which is subject to the incentive mechanism. To mitigate risks to both the utility and customers, it is common practice to implement “caps and collars” to mitigate the overall strength of particular incentive mechanisms. A key example of such arrangements can be seen in the British market where electricity distribution companies have a maximum of $\pm 3\%$ of annual revenues linked to the incentive mechanism seeking improvements in the quality of supply (numbers and duration of interruptions to customers).

Another feature of incentive design which regulators must consider is the duration of the incentive before the baseline is reset. In jurisdictions where multi-year regulatory settlements are established, it is commonplace for the duration of the incentive to be aligned with the regulatory period. It is often the case that the annual benefits (penalties) achieved in one year also apply in the subsequent years of the regulatory period, and are only reset during the next regulatory review.

With some incentive mechanisms, regulators have set targets which tighten incrementally in each year of the regulatory period in order to maintain a strong performance improvement driver. However, it should be recognized that continual performance improvement may not be realistic or the cost of performance improvement may become inefficient relative to the incremental benefit being delivered to customers. Consequently, as incentive mechanisms mature the setting of targets becomes increasingly challenging, otherwise there is a risk that distortions can arise where the regulated companies are incentivized to pursue sub-optimal outcomes.

A final point to acknowledge when setting targets and incentives is that no two utilities are exactly alike. Therefore, regional factors such as asset age considerations, historic design philosophies, and customer characteristics (e.g., urban/rural apportionment) need to be considered when setting targets and different targets and incentive rates may need to be applied to different utilities.

Use of incentivization within network utility revenue controls is not widely applied by international regulators as it can be complex to implement and difficult to monitor, thus requiring strong underlying regulatory focus and perceived strong benefit drivers to be viewed as worthwhile. Of the regulators reviewed in detail by KEMA for OEB staff, it is the Office for Gas and Electricity Markets (commonly referred to as Ofgem) in Great Britain (Section 4.4.3) which most extensively uses incentivization in a number of different areas but incentivization is also used by regulators in Australia (Section 4.4.1) and New Zealand (Section 4.4.4). Incentive rates have also been successfully implemented in various jurisdictions within the US market (Section 4.4.5).

3.10 Use of Output Measures

The final broad assessment methodology that regulators have at their disposal is the use of output measures. This is an emergent technique in the field of network utility regulation seen as a means of reducing the regulatory burden on both the utility companies and the regulator while simultaneously improving the transparency of investment plans. The use of output measures is an area which is at the frontier of development of regulatory approaches, methodologies, and tools for review of network utility investment plans and supporting asset management activities.

To some extent output measures form an extension or natural progression to incentivization where revenue rewards or penalties can accrue dependent on whether network utilities are seen to be “doing the right thing” within the framework of regulatory objectives for network utility behavior. However, it is more challenging to apply as it seeks to explicitly and transparently link revenues provided by the regulator to fund network utility investment plans and supporting asset management practices to quantified desirable outputs.

The development of suitable metrics, which capture process outcomes (as opposed to inputs), is valuable in the fields of network performance, asset health, network capacity and risk as

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these provide a snapshot of the key challenges facing a utility. More importantly, over time these output measures can be used to identify associated trends which can then be related to investment requirements. For example, where an output measure relating to asset health shows a gradual deterioration over time, this can signal the need for increased investment. In addition, the improvements of a particular output measure can be related to corresponding levels of expenditure such that indications of value and efficiency can be derived.

As part of the regulatory scrutiny of investment plans, output measures may be used to clarify the improvements (or reduction) being forecast/sought by the utility over the next regulatory review period which can subsequently be checked at the next regulatory review. This will allow the future movement in output measures to form part of the “contract” between the utility and regulator to quantify and validate the return on investment customers will receive from utility expenditure.

Another benefit of incorporating output measures within the regulatory review cycle is that it incentivizes rigor with respect to investment forecast accuracy. The use of output measures challenges the utility to link how their asset base will evolve relative to different amounts of expenditure and thus facilitates corresponding sensitivity analysis. The development of a portfolio of output measures also challenges the utility to consider what levels of asset condition, risk performance etc., are appropriate now and in the future.

Some output measures are relatively straightforward to identify. A good example is Customer Incidents and Customer Minutes Lost (CI and CML) which are two output measures measuring a specific aspect of customer service from network utilities. While these are used to assess network utility performance by most regulators and by some for incentivization, other output measures are harder to capture, quantify, or link to network utility investments and activities. For example, how can network risk be captured; how is network condition quantified; and how is investment linked accurately to asset management activities and asset health?

To capture some network utility activities effectively there needs to be complexity of output measures. However, regulators face the challenge of needing this complexity to relate output measures to key regulatory objectives, while at the same time seeking to ensure these output measures are transparent and understandable to both the network utility and regulator. The aim of this balancing act is to best ensure appropriate network utility actions/behavior and enable clear regulator (and other stakeholder) oversight of what output benefits are being derived from investment. This is a problematic balance to strike.

Finally, for the regulator, the desire is to identify output measures that are ideally leading indicators or are coincident indicators of network utility performance/issues requiring investment and/or improved asset management. Clearly an output measure that is a lagging indicator simply tells you that investment should have been made after performance has become unacceptable or failed (i.e., it is too late). This adds to the difficulty in applying output measures.

Developing a full suite of output measures which capture all aspects of network utility activities and which directly relate to network utility investment plans and asset management practices is extremely challenging to achieve – and is probably only possible via degree of cooperation and co-development by regulators and network utilities. Consequently, as of today, no international energy regulators have yet implemented such a comprehensive regime. Where output measures have been applied by international regulators these have been for narrow and easily quantified aspects of impact of network utility investment plans and asset management practices – and typically subject to some form of revenue incentivization.

The development and use of output measures is a key feature of 5th Distribution Price Control Review in Great Britain (Section 4.4.3) and various jurisdictions within the US have also implemented performance-based rate mechanisms (Section 4.4.5).

3.11 Overview of Regulators Use of Regulatory Tools

In the previous sections we have examined ten different potential regulatory approaches which can be applied in the review of network utility plans and underlying asset management practices. In this section we provide an overview of these ten approaches and highlight:

- 1) Their relative importance (from “must” to “optional” and, if applicable, highlight any interdependencies/exclusivities);
- 2) The context of their application (i.e., why different regulators apply different portfolios of these tools and why they apply them differently); and
- 3) The extent of application of the ten “tools” by international regulators in their review of network utilities.

The table below summarizes this analysis. The hierarchy of importance adopted in the table is as follows:

- **Highest:** Necessary, Important, Useful; and
- **Lowest:** Optional.

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Table 1: Overview of Regulatory “Tools” for Network Utility Assessment & Extent of Their Use

Regulatory Approach	Relative Importance and Context of Use	Extent of Use <i>(examples from KEMA international market review)</i>
Ex ante assessment	Necessary – critical to ensure cost control and protect consumers from monopoly abuse. Is applied in all contexts.	Universal <i>(all)</i>
Ex post assessment	Useful – is typically used where materiality is high (large utilities; large overall spend) and high uncertainty at time of ex ante assessment (e.g., volatile economic climate; unpredictable connection activity).	Limited <i>(Great Britain)</i>
Expert third party input	Necessary – especially applied where there is review of large network utilities and/or where there are large numbers of network utilities to provide specialist/depth of knowledge to combat information asymmetry and/or to provide resourcing to deliver scale of review.	Most <i>(Australia, Great Britain, New Zealand)</i>
Periodic multi-year controls	Useful – used for maintaining systematic understanding and control of investment and asset management activities especially for large network utilities with material spend and impact on customers.	Most <i>(Australia, Great Britain, Germany)</i>
Review of practice vs. policy	Useful/Important – applied where strong focus on asset management (due to aging infrastructure; or high performance requirements; or high impacts of network events) and/or materiality is high (per utility or overall) and high uncertainty at time of ex ante assessment (unpredictable future impacting on network development needs and costs) – increasingly important where there are larger networks and/or increasingly material investment spend and/or network impact on customers.	Limited <i>(Australia, Great Britain)</i>
Reporting & monitoring	Useful/Important – for same reasons as above; plus also helps to combat information asymmetry (vs. large network utilities) and retain “corporate memory of regulator” (where large number of utilities, large amount of data and/or extended periods between major Price/Rates Reviews).	Most <i>(Australia, Great Britain, New Zealand)</i>
Intervention triggers	Optional – typically applied where high uncertainty at time of ex ante assessment and/or strong focus on performance delivery. Also useful to protect customers where otherwise light touch regulation (due to utility size or numbers) to protect customers e.g., Germany applies 1% deviation trigger on their simplistically derived asset replacement expenditure allowance.	Limited <i>(Great Britain and Australia in extremis; US and Germany in limited manner)</i>
Benchmarking	Important – enables strong understanding of relative performance and where peers exist; driving peer competition – at low overhead cost to regulator. Thus, especially used where many utilities within market but also for larger network utilities with investors (and share price).	Most <i>(Australia, Great Britain, New Zealand)</i>
Incentivization	Useful/Important - is applied where strong regulatory focus on influencing specific aspects of network utility activities/behavior e.g., reduction in environmental impact; connection of DG, innovation. Is more important where regulator more actively seeks to influence network utility behavior e.g. in Great Britain.	Most <i>(Australia, Great Britain, New Zealand)</i>
Output measures	Optional/Useful – is an option other than ex-post assessment and is applied in the same context (see ex-post assessment above). In addition, is sought to be applied where particularly strong regulatory focus on influencing a balanced approach to asset management (cost, risk, sustainability) and where there is otherwise strong information asymmetry (e.g., large utilities) by making explicit relationships between investment and different measures of performance. Is applied where seek to influence behavior ex-ante rather than ex-post.	Emergent <i>(Great Britain to apply)</i>

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It can be seen from the table above that only ex ante assessment is universally applied in the review of network utility investment plans and underlying asset management practices. This is because it is the best mechanism for protecting customers from unduly high costs (and therefore tariffs) and minimizing the risk of inefficient investment.

Most regulators (e.g., Australia, Germany, Great Britain, and New Zealand) also adopt periodic multi-year reviews, use expert third party support, and employ comparative benchmarking. This is because these measures allow regulators to develop strong knowledge and understanding of network utilities and retain expert oversight over network utility activities.

Some regulators review practice versus policy, apply (typically annual) reporting and monitoring processes, apply intervention triggers, and also apply some form of incentivization regime(s). This tends to be applied in markets (e.g., Australia and Great Britain) where there is the strongest focus on asset management. The use of these measures tends to be driven by a combination of regulating large network utilities with high materiality of investments, high degree of future uncertainty over investment needs, presence of aging (near end of life) networks and regulators seeking specific key behaviors (or behavioral changes).

Finally, only the Great Britain regulator is currently seeking to introduce a full suite of output measures to regulate network utilities. These are currently being developed within the ongoing electricity Distribution Price Control Review in Great Britain and is driven by a combination of underlying issues of network assets nearing nominal end of life, consequential high and escalating materiality of investments, framed in the context of high degree of future uncertainty over investment needs, and desire to enforce appropriate balance of cost, performance and risk.

4. Approaches to Regulatory Assessment of Network Utility Investment Plans

This section provides a discussion and comparison of the regulatory approaches adopted internationally for the assessment of network utility investment plans and underlying asset management practices. It is based on an in-depth review of a selection of international energy jurisdictions which KEMA believes provides representative coverage of:

- 1) Regulatory practices in developed energy markets worldwide (i.e., Europe, North America and Australia);
- 2) The range of different regulatory approaches adopted in international energy jurisdictions;
- 3) The differing level of maturity/sophistication of regulatory practices internationally; and
- 4) Markets with similar industry structures (e.g., types and numbers of utilities).

The markets selected for review are Australia, Germany, Great Britain, New Zealand, the US and Canada (British Columbia). The full examination of these markets and the regulatory practices adopted within them in relation to assessment of network utility investment plans and underlying asset management practices are provided in the Appendices. However, in this section we seek to draw out key principles and points of regulatory practices across these markets, as well as examples of regulatory practices specific to individual markets.

4.1 Differential Treatment by Type of Utility

An important aspect of regulatory practices adopted internationally is the variation in detailed approaches in reviewing investment plans and underlying asset management practices adopted for different types of network utility. Specifically:

- 1) Distribution versus transmission networks; and
- 2) Electricity versus gas networks.

Before undertaking an assessment of the investment plans, it is worthwhile highlighting key physical differences between transmission and distribution, and between gas and electricity, which may drive different investment plan assessment processes. This section examines these characteristics and how this drives differences in regulatory approaches across different types of network utility.

4.1.1 Areas of Differentiation between Transmission and Distribution

There are some key differences in the detailed approach adopted by most regulators in conducting assessments of utility plans at a transmission level versus a distribution level. These arise from key differentiating characteristics of transmission and distribution networks and apply to gas and electric networks. They are summarized in the table below:

Table 2: Differentiation between Transmission and Distribution

Transmission	Distribution
<ul style="list-style-type: none"> ▪ Assets have individual high value ▪ Relatively low numbers of assets ▪ Many assets bespoke ▪ Investment schemes non-homogenous ▪ Consequence of asset failure can be high ▪ Asset construction lead times long ▪ Actively managed network ▪ High voltages/pressure – low losses ▪ Low end user interface (few customers) 	<ul style="list-style-type: none"> ▪ Most assets have low individual value ▪ High numbers of assets ▪ Relatively few assets are bespoke ▪ Investment schemes relatively standardized ▪ Consequence of asset failure mostly low ▪ Asset construction lead times mostly low ▪ Traditionally passive network ▪ Lower voltages/pressure – higher losses ▪ High end user interface (many customers)

The differences outlined above lead to the following divergences in the detailed assessment techniques commonly adopted by regulators.

- A key differentiator between transmission and distribution activities is the relative focus on bottom-up techniques and top-down techniques for deriving investment plans.
 - For transmission, the assessment of investment plans are much more scheme specific than in distribution, emphasizing a primarily bottom-up assessment philosophy. As an example, a common thread throughout all UK Transmission Price Control Reviews (TPCRs) has been an Ofgem focus on the efficiency of scheme design in terms of options considered for individual major investments, and in terms of design coordination for a number of related schemes. This reflects the high individual scheme costs for transmission, but also their lower numbers and the inherently bespoke nature. Hence, there is extensive scrutiny of investment identification (what), justification (why), specification (how) and timing (when) within TPCR.
 - For distribution, the assessment of investment plans are more focused on collective requirements, emphasizing a top-down assessment philosophy – modeling (top-down) versus condition assessment (bottom-up). The substantially higher number of low value assets employed within distribution networks, coupled with the option of replacement upon failure (rather than before), lends itself to statistically more robust asset

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life based replacement modeling. Equally, the lower individual asset costs do not merit scrutiny on an equipment-specific basis. This also allows for more comparative benchmarking of distribution companies as there are less special schemes that require specific assessment.

- Due to the higher impact of asset/network failure at the transmission level, regulators typically place a significantly higher degree of scrutiny on the perceived level of asset risk and overall network risk, which transmission network businesses are seeking to address via investment plans. Key areas of discussion surround the appropriate level of risk to be tolerated; how this is measured and monitored; what is an acceptable cost to mitigate undesirable risks; and what alternative risk mitigation measures could be applied other than investment? Distribution network businesses have greater latitude to adopt varied risk positions (and thus varying investment plans for comparable circumstances) due the lower consequences of risk related events.
- Due to the different scale and lead time of transmission network investments compared to distribution network investments, regulators spend far greater assessment time reviewing proposed strategic investments by transmission networks. These are required to meet proposed future long-term network related developments such as changes in primary locational sources of gas or development of substantial renewables resource in remote and offshore locations.
- Transmission remains largely distinct from distribution in that transmission networks are dynamic interconnected networks actively managed in real time (i.e., subject to active network management or system operation), whereas the distribution networks are largely passive networks simply enabling demand to be fulfilled without active intervention. *Despite the evolution of the concept of Smart Grids, this will remain the general case for many years yet.* Also, component assets are of much higher individual value in transmission networks. Consequently, there is a far greater opportunity for and need for the scrutiny of capital expense versus operating expense solutions at a transmission level. For example, it may be more cost beneficial to manage a transmission constraint operationally over a finite period of time than invest to relieve it (thus putting focus on drivers of the constraints; their duration, severity and operational cost consequences). In addition, asset refurbishment and enhanced maintenance techniques may become economically viable alternatives to simple asset replacement approaches.

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- As a general rule, distribution networks are less efficient in energy transport than transmission networks – for example in Germany the average annual transmission losses are approximately 2% and average annual distribution losses are in the range of 4-5%. Thus, regulators tend to place greater specific scrutiny on the nature of investments that distribution networks make (i.e., the type of equipment and its losses performance) to seek to prevent undue levels of energy losses in the network.
- In a wider context, the focus of scrutiny on environmental impact varies between distribution and transmission in that the sources of major environmental impact (such as emissions, pollution, and visual amenity) differ between the two. As a rule, focus for distribution is largely in the route elements (e.g., voltage/pressure transformation) whereas for the transmission the focus is largely placed on the nodal parts of the network (e.g., substations where assets such as SF6 switchgear and oil-filled cables are a key factor given their high pollutant potential).
- Finally, as the number and types of users are very different between transmission and distribution, the emphasis regulators place on assessing stakeholder support for elements of the investment plans, or alternatively, how elements of the investment plans help improve service for users (e.g., quality of supply) is different. For distribution network investment plans, regulators will tend to seek much wider input from varied stakeholder groups on their views of what should be and should not be included in investment plans, and what outcomes investment plans should seek to deliver from their perspective(s). These stakeholders include industrial, commercial, and domestic users, energy suppliers, local authorities, and local interest groups. For transmission networks' investment plans, regulators tend to seek views from a small group of more business-to-business or national oriented stakeholder groups (e.g., large generators, distribution network owners, large industry, and national policy groups).

4.1.2 Areas of Differentiation between Gas and Electricity

There are clearly physical differences (e.g., functions and types of assets) between electricity and gas networks which reflect the different physical nature of electricity and gas as forms of energy. This has led to differences in the regulatory approach applied by a number of regulators. These key differences are outlined in the table below.

Table 3: Differentiation between Gas and Electricity

Electricity	Gas
<ul style="list-style-type: none"> ▪ Electricity networks fail “safe” ▪ High proportion of assets near end of life ▪ Distribution connections competition limited ▪ High level of transmission connections ▪ Generation must essentially equal demand in real time 	<ul style="list-style-type: none"> ▪ Gas networks fail “unsafe” ▪ Lower proportion of assets near end of life ▪ Distribution connections fully competitive ▪ Low level of transmission connections ▪ Gas can be stored

The differences outlined above lead to the following differences in detailed assessments:

- **Consequences of failure** – There is higher danger to life posed by failure of the gas network, which typically results in gas leakage that may ignite and explode than from electricity networks where failure typically results in de-energization of certain equipment and simple loss of supply. As such, there is presence of more onerous legal requirements and liabilities for the gas network companies under health and safety legislation that exists in most markets. Consequently, for gas networks, there is far greater emphasis on safety related assessment of investment plans (as well as other relevant activities). This emphasis is much greater in relative terms between electricity distribution and gas distribution where network failure in the latter for a household can easily lead to multiple deaths amongst the public. An example of this emphasis is shown by the legal requirement, enforced by the UK Health and Safety Executive, that all sites of reported domestic gas leaks must be attended to within one hour of notification. This contrasts to failure of electricity supply which can be allowed to occur for up to 12 hours before the UK regulator specifies financial penalties that begin to arise.

- **Age of networks** – Much of the current transmission electricity network in countries with well developed energy markets and network infrastructure was built in the 1960’s or 1970’s consisting of assets with nominal lives of 40 years and thus a high proportion of assets are nearing end of life. Similarly, many distribution network assets are beginning to reach nominal “end of life” status. In contrast, much of the gas network, especially at the transmission level, is relatively young given its development was driven by discovery of substantial gas reserves from the 1970’s onwards, in for example the UK, Norway, Russia, the Gulf of Mexico, and the development of associated network infrastructure to transport this gas to meet growing use for both domestic heating and power generation. Consequently, there is generally a far greater emphasis of understanding drivers of asset replacement in electricity network businesses.

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- **Levels of connection competition** – At a distribution level in some countries, gas connections are a fully competitive market in which distribution network developers compete on an unregulated basis. In certain places such as New Zealand, this has developed to the stage where companies such as Nova Gas provide competing networks with the incumbent gas network companies. This contrasts to electricity where there is only limited competition seen for larger (industrial) connections in some markets such as the UK and the majority of connections remain provided via regional monopoly businesses. Consequently, while review of connections is a key aspect of electricity distribution investment plans it is not as applicable in the gas distribution context.
- **Number, magnitude and uncertainty of connections** – In recent years there have been numerous requirements to connect new generation stations (largely renewable) within a portfolio aging fossil fuel plant mix leading to very high level of connection activity, and uncertainty of future investment needs for electricity networks. In contrast, entry points for gas are relatively few and stable. Consequently, there is far more focus on proposed investment driven by changes in input to the network (i.e., generation) and justification/sensitivity of this for electricity than there is for gas where there are more limited gas sources and longer lead times for development of these (and new sources where found).
- **Granularity of demand balancing** – Finally, as a general rule, electricity generation must match demand in real time, and thus at a transmission level it is crucial that, taking into account potential short-term operational measures to resolve real time mismatches, investment in the network ensures appropriate quality and security of supply. The consequences of under-investment and inability to address short-term mismatches with operational measures following system events (e.g., asset failure) can be severe (e.g., leading to power blackouts). In contrast, gas can be stored in dedicated storage facilities and in the pipelines themselves. Gas also “moves slowly” relative to electricity and thus it is easier to address imbalance in injection and extraction from the network in real time. There is therefore a greater tolerance within the gas network to unexpected events and there is less need for inclusion of and assessment of investments within the investment plans to provide network resilience.

4.2 Characteristics of International Markets

In comparing different international regulatory approaches it is worthwhile considering key features of each market to provide an understanding of the underlying context which lies behind the differing regulatory practices. The tables below provide overview information on the selected international markets we have reviewed in depth as part of this study. This includes:

- Number and size of companies in each market sector (gas/electric and transmission/distribution);
- Ownership structure of network utilities; and
- Extent of vertical integration.

These factors can have a strong influence on the regulatory approaches adopted for assessment of network investment plans and supporting asset management strategies.

4.2.1 Market Size and Company Characteristics

This is broken down into electricity transmission, electricity distribution, gas transmission, and gas distribution.

4.2.1.1 Electricity Transmission

Except for the US, the markets studied have similar average system length per company despite significant geographic size differences. Some caution should be taken with these figures as the voltages classified as transmission may vary between markets. The averaging of the figures hides considerable variability between companies within a market. However, all companies are of a size that would justify investigation into their planned capital expenditure.

In the US, most transmission assets still reside within vertically integrated utilities; however, a few transmission-only companies exist due to industry structure and deregulation factors. For example, Tennessee Valley Authority (TVA), Bonneville Power Authority (BPA), and Nebraska Public Power District (NPPD) are government-owned transmission-only utilities. The Georgia Transmission Corporation (GTC) was formed to serve utility cooperatives (co-ops) in the State of Georgia, while the International Transmission Company (ITC) evolved out of deregulation efforts in the State of Michigan.

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Table 4: Key Characteristics of Transmission Companies in Different Jurisdictions

Country	No of Transmission Companies	System Length (km)	Average System Length per company	Highest System Length	Lowest System Length
Australia ²	7	47,908	6,844	12,489	1,040
Germany	4	57,102	14,275	32,600	3,644
Great Britain	3	24,033	8,011	15,089	4,031
New Zealand	1	11,800	11,800	11,800	11,800
USA ³	3,100	263,898	85	62,764	N/A
Canada (BC)	3	19,470	64,900	18,000	20

4.2.1.2 Electricity Distribution Companies

The UK and Australia have a relatively small number of distribution companies with a relatively high average number of customers. New Zealand has a wide variation in the size of its distribution companies with the smallest companies having just over 4,000 customers, while the largest company had a third of the market with 600,000 customers⁴. Germany has the lowest average customers per company with 650 of the 855 companies having less than 30,000 customers. Clearly it would not be economically efficient to apply the same regulatory approach to these small companies as seen in the UK where companies have an average of 2 million customers each.

Table 5: Key Characteristics of Electricity Distribution Companies

Country	No of Distribution Companies	Line Length (km)	Number of Customers	Average Line Length (km)	Average Number of Customers
Australia	14	767,037	9,562,143	54,788	683010
Germany	855	1,614,198	c. 44,500,000	1,888	c. 520,468
Great Britain	14	761,508	28,432,000	54,393	2,030,857
New Zealand	29	144,165	1,823,070	4,971	62,864
USA ⁵	3,100	N/A	137,298,683	N/A	44,290
Canada (BC)	13	61,550	1,938,353	4,735	149,104

² All statistics cover the NEM region and Western Australia. The NEM region is regulated by a single regulator and includes Queensland, New South Wales, Australian Capital Territory, Victoria, Tasmania and South Australia. The one state that is not included is Northern Territory, which has no Electrical Transmission system and only a small number of customers.

³ Source: Energy Information Administration Form 861 – Electric Power Industry Report 2007. North American Reliability Corporation Long-Term Reliability Assessment 2008. The listed statistics are for “bundled” utilities that have both T&D operations.

⁴ This company has now been split into 2 with part of the assets being sold.

⁵ An incumbent U.S. utility is both a transmission and distribution utility and thus the listed number of T&D companies is the same. To date, the EIA has not separated transmission and distribution utilities in its statistical surveys. Estimated date for a separate transmission category is between 2009 and 2011 reporting periods.

4.2.1.3 Gas Transmission

Australia and Germany have a high number of gas transmission companies which exist on a regional basis. This contrasts to Great Britain with only one transmission company and New Zealand where two companies own the majority of pipelines in the country. Some caution should be taken with looking only at system length. As an example, in New Zealand the smaller company with only 1/8th of the network length transmits more gas by volume.

Table 6: Key Characteristics of Gas Transmission Companies

Country	No of Transmission Companies ⁶	System Length (km)	Average System Length per company	Highest System Length	Lowest System Length
Australia	10	9,271	927	2035	47 ⁷
Germany	20	61,000	3050	n/a	n/a
Great Britain	1	6,400	6400	6400	6400
New Zealand	2	2527	1263	2218	308
USA (Lower 48 States)	83 ⁸	345,402	4,161	25,355	724
Canada (BC)	11	N/A	N/A	N/A	N/A

4.2.1.4 Gas Distribution Companies

There is a considerable difference in the number and size of distribution companies that exist in the different markets. This is most notable when comparing Germany with over 697 companies to Great Britain with four. Germany stands out in the table as having a low average line length for each distribution company even when compared with New Zealand and Australia. It also has a low number of customers per company with 540 of their companies having less than 30,000 customers each.

The UK is unusual with the large average size of its gas distribution businesses. This justifies far more regulatory inspection of the capital investment plans.

⁶ Only regulated pipelines are covered. Some countries such as Australia have a number of unregulated pipelines.

⁷ This is the second smallest pipeline as the smallest pipeline does not have an access arrangement approved. It is a similar size at 44km

⁸ Transmission of natural gas in the U.S. is divided into two reporting classes: interstate and intrastate. For the purpose of comparison, interstate has been defined as ‘transmission and intrastate as ‘distribution’.

Table 7: Key Characteristics of Gas Distribution Companies

Country	No of Distribution Companies	Line Length (km)	Number of Customers	Average Line Length (km)	Average Number of Customers
Australia	12	81,289	3,505,000	6,774	292,083
Germany	697	314,000	16,442,400	451	23,590
Great Britain	4	262,500	21,178,600	65,625	5,294,650
New Zealand	3	12,670	250,581	4223	83,527
USA (Lower States)	48	74	140,563	70,427,641	1,900
Canada (BC)	11	N/A	954,532	N/A	86,776

4.2.2 Ownership Type (Private/Publicly Owned)

This section describes the ownership structures of the companies, which may be a factor that drives the extent of regulatory assessment (e.g., light touch regulation in New Zealand).

4.2.2.1 Electricity Transmission

Electricity transmission companies have a mixture of ownership structures. The Great Britain and German companies are all privately owned, which they have been for some time, although in Germany some local municipalities have shares in the TSO. In New Zealand, the transmission company is state owned as are the majority of companies in Australia. The US has a mixture of private, public and community ownership. In British Columbia, an independent Crown-owned transmission corporation was established to maintain, operate, and plan transmission assets owned by the dominant Crown-owned transmission and distribution company.

Table 8: Ownership of Electricity Transmission Companies

Country	Ownership
Australia	Majority (5 from 7) Government owned. Two privately owned but one of the shareholders is a State Government.
Germany	All privately owned in principle, but some municipalities have shares of the TSO.
Great Britain	All privately owned.
New Zealand	State owned corporation.
USA ⁹	293 Investor-Owned, 1,845 Municipally-Owned, 936 Cooperatives, and 26 Federally-owned utilities.
Canada (BC)	6 Investor-Owned, 6 Municipally-Owned, 2 Crown-owned.

⁹ Due to the ‘bundled’ nature of U.S. utilities, the ownership figures are listed as the same for both transmission and distribution.

4.2.2.2 Electricity Distribution

The pattern with electricity distribution is similar to transmission. Again, all Great Britain companies are privately owned. However, in comparison to transmission, more of the Australian utilities are in private hands and in New Zealand there is some private sector ownership, but the majority of companies are owned by Energy Trusts, representing the local community. In Germany, the largest companies are privately owned although the large number of smaller companies comprise a mix of privately owned and local authority/municipally owned companies. In the US markets there is a varying mix of privately owned, municipally owned, and customer owned cooperative (co-op) utilities.

Table 9: Ownership of Electricity Distribution Companies

Country	Ownership
Australia	Split with 7 of the 14 Government owned. The rest are privately owned although one has a 50% Government share.
Germany	The large companies are privately owned. Smaller companies comprise a mix of privately owned and municipally owned companies.
Great Britain	All privately owned.
New Zealand	The majority of distribution companies are owned by energy trusts on behalf of communities and consumers. There are a couple of the largest distributors that are now privately owned.
USA	293 Investor-owned, 1,845 Municipally-owned, 936 Cooperatives, and 26 Federally-owned utilities.
Canada (BC)	6 Investor-owned, 6 Municipally-owned, 2 Crown-owned utilities.

4.2.2.3 Gas Transmission

The gas sector is different from the power sector in being predominately owned by private sector companies. In some countries like Great Britain this is the result of privatization from public ownership, while in other countries such as Australia, some of the transmission lines were originally built by the private sector and some by the Government sector and then privatized.

Table 10: Ownership of Gas Transmission Companies

Country	Ownership
Australia	All private sector owned.
Germany	All privately owned.
Great Britain	All privately owned.
New Zealand	One private sector owned and one owned by a company that is ultimately majority owned by an Energy Trust.
USA	All are privately-owned or publicly held. ¹⁰
Canada (BC)	All are investor owned or publicly held.

¹⁰ Energy Information Administration Natural Gas Pipeline Listings

4.2.2.4 Gas Distribution

Gas distribution companies are predominately private sector owned. New Zealand is an exception as the majority of customers are supplied by distribution companies that are ultimately customer or council owned.

Table 11: Ownership of Gas Distribution Companies

Country	Ownership
Australia	One and a half of the 12 utilities are Government owned the rest are held by the private sector.
Germany	The large companies are privately owned. Smaller companies comprise a mix of privately owned and municipally owned companies.
Great Britain	All privately owned.
New Zealand	Of the three major companies one is private, one is ultimately majority owned by an Energy Trust, and one is majority owned by a District council. There is an additional privately owned distribution network that competes with other network operator rather than having an incumbent area.
USA	All are privately owned or publicly held.
Canada (BC)	All are investor owned or publicly held.

4.2.3 Vertical Integration

An area that may guide the degree of regulatory control is the vertically integrated nature of the company and whether there is the possibility to position costs away from the non-regulated part of the company. An overview of the position in each country is shown below:

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Table 12: Level of Vertical Integration in the Market

Country	Electricity Transmission and Distribution	Gas Transmission and Distribution
Australia ¹¹	<p>Three of the transmission companies also have distribution business.</p> <p>NSW and Tasmania have common ownership in electricity distribution and retailing (with ring fencing for operation separation). In Queensland one of the distributors still provides retail services to some customers.</p> <p>In addition, some of the electricity network companies also own gas businesses.</p>	<p>Gas Transmission and Distribution companies are separate businesses.</p> <p>Some of the gas distribution companies do have retail arms.</p>
Germany	<p>The TSO are legally unbundled from all other energy activities.</p> <p>For distribution companies with less than 100,000 customers - no separate legal/ownership required thus a number are part of companies with wider interests (not just in energy sector).</p>	<p>The TSO are legally unbundled from all other energy activities.</p> <p>For distribution companies with less than 100,000 customers- no separate legal/ownership required thus a number are part of companies with wider interests (not just in energy sector).</p>
Great Britain	<p>There is one company which owns the electricity GBSO; an electricity transmission company for England & Wales, the Great Britain gas transmission company and 4 gas distribution companies.</p> <p>There are two companies which each own an electricity transmission company in Scotland, an electricity distribution company in Scotland and an electricity distribution company in England. Each also own ring-fenced generation and supply interests in Great Britain. One of these companies also owns the gas distribution company for Scotland and another regional gas distribution company in England.</p> <p>There are two companies which own regional electricity distribution companies within a vertically integrated portfolio also owning generation and supply. One of these owns 3 regional electricity distribution companies; the other owns two regional electricity companies.</p> <p>There are also three companies who just own regional electricity distribution companies (two of whom own cover 2 regional areas each).</p> <p>Finally, there are two companies which only own individual gas distribution companies.</p>	
New Zealand	<p>The transmission company is separate from all distribution companies</p> <p>Cross ownership between lines and retail companies was prohibited under the Electricity Industry Reform Act 1998 which required ownership separation.</p> <p>Cross ownership exists between gas and electricity networks with Vector and Powerco having a large gas and electricity network.</p>	<p>The owner of the major transmission network also owns two of the 4 regulated distribution networks.</p> <p>All the major gas distribution networks have retail subsidiaries.</p>
USA	<p>Vertically integrated utilities remain in States that did not deregulate.</p> <p>Unbundled distribution and transmission exist in deregulated markets</p>	<p>Gas transmission and distribution has been unbundled as the result of FERC order.</p>
Canada (BC)	<p>The transmission and distribution network is dominated by one commercially owned Crown corporation that serves 95% of the population. The remaining 5% is served by five investor-owned utilities and six municipal utilities.</p> <p>An independent Crown company was incorporated in 2003 to maintain, operate, and plan the transmission assets owned by the dominant transmission company to ensure open and non-discriminatory access to the B.C. transmission system for all electricity producers.</p>	<p>The BC natural gas industry is characterized by transmission and distribution monopolies with a competitive supply market. The industry is not vertically integrated and transmission and distribution services may or may not be provided by the same company.</p> <p>The BC Utilities Commission regulates the transmission and distribution of natural gas but does not regulate the competitive market natural gas; however, it requires utilities to provide quarterly reviews of gas prices and deferral account balances (established to smooth changes in utility rates).</p>

¹¹ All Australian references exclude the Northern Territory

4.3 Overview of International Approaches to Regulation

4.3.1 Structure of Regulation

An important initial comparison is to consider whether gas and electricity utilities are seen as providing a similar service and therefore subject to the same economic regulator. This consistency of regulator is likely to lead a similarity of approach for approval of investment plans and requirements for asset management which underpin/drive these investment plans/requirements.

Table 13: Economic Regulator for Each Utility

Country	Electricity Transmission Regulator	Electricity Distribution Regulator	Gas Transmission Regulator	Gas Distribution Regulator
Australia ¹² NEM Region/Western Australia	Australian Energy Regulator/ Economic Regulation Authority	Australian Energy Regulator/ Economic Regulation Authority	Australian Energy Regulator/ Economic Regulation Authority	Australian Energy Regulator/ Economic Regulation Authority
Germany	Federal Regulator called the Bundesnetzagentur	Federal Regulator called the Bundesnetzagentur and Regulator of the Federal States ¹³	Federal Regulator called the Bundesnetzagentur	Federal Regulator called the Bundesnetzagentur and Regulator of the Federal States
Great Britain	Ofgem	Ofgem	Ofgem	Ofgem
New Zealand	Commerce Commission/ Electricity Commission	Commerce Commission	Commerce Commission	Commerce Commission
USA	Federal Energy Regulatory Commission (FERC)	State Public Utility Commissions (PUC's)	Federal Energy Regulatory Commission (FERC)	State Public Utility Commissions (PUC's)
Canada (BC)	British Columbia Utilities Commission (BCUC)	British Columbia Utilities Commission (BCUC)	British Columbia Utilities Commission (BCUC)	British Columbia Utilities Commission (BCUC)

It is interesting that many countries have recently moved towards a single regulator rather than many regulators. This was done in a compulsory way for the NEM region in Australia, where the Australian Energy Regulator (AER) has recently taken over responsibility for economic regulation of gas and electricity networks in the region. The same process is also being achieved in a voluntary way in Germany with some of the federal states choosing to let the Federal Regulator control even the smaller utilities (which they can regulate themselves). There appear to be a several drivers for this:

¹² All Australian references exclude the Northern Territory

¹³ The Regulation Authority of the federal states is responsible for all network operations with less than 100,000 customers connected directly or indirectly to their grid. Some have transferred responsibility to the Federal Regulator (Bundesnetzagentur)

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- 1) Consolidation of expert regulatory capability within a single body to maximize effectiveness of network utility regulation across gas and electricity, distribution and transmission;
- 2) Ability to apply continual learning from regulatory exercises and to roll this out consistently and appropriately to all network utilities;
- 3) Increased utility consolidation and multi-utility companies requiring better resourced and more intensive sophisticated regulation;
- 4) Increased integration of electricity and gas markets (e.g., interdependency driven by gas-fired generation) and distribution and transmission issues (e.g., network performance and asset replacement) requiring more integrated regulatory understanding and approaches;
- 5) Ease of accountability and access for stakeholders to regulators (e.g., government, consumers); and
- 6) On an international front, where regulators are involved in meetings, discussions, and participate in conferences, it is easier to deal with one single regulator in order to avoid confusion and this also enhances continuity on a long-term basis.

However, regulation in the US remains a mix of federal and state-level agencies. The Federal Energy Regulatory Commission (FERC) regulates interstate gas and electric transmission, while individual state commissions (PUC's) regulate companies within their jurisdictions, and local government entities regulate municipal utilities.

4.3.2 Elapsed Time to Establish New Price Control

An indication of the general level of assessment required as part of the overall Price/Rates Review process can be seen by the time allowed to reach a decision on the next form of regulatory control that will apply to the network. This is shown in the table below:

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Table 14: Elapsed Time to Establish a Price Control

Country	Electricity Transmission and Distribution Regulator	Gas Transmission and Distribution Regulator
Australia	NEM region – Approx 10-11 months after proposal submitted. Will be pre-consultation discussions prior to submission of proposals. Company obligation is to submit proposal 13 months before determination due. Western Australia has a similar timetable.	AER – Final decision is due in 135 business days from proposal submission. 6 months are also allowed for pre-consultation. WA – Anticipated that similar timescales to AER will apply.
Germany	For the current price control (first price control under incentive regulation) from Jan 2009, the initial proposal for the design of the price control was published 30 June 2006, followed by consultation process with industry and relevant stakeholder providing feedback. The final Incentive Regulation Ordinance came in to force in November 2007. This resulted in a lead time of just over one year until actual commencement of the price control. During this period, ongoing discussions between the regulator and the TSO/DSO continued especially concerning specific elements of the price control. An example was the benchmarking exercise and the efficiency scores of the TSOs and DSOs were communicated to them in Dec 2008. For the regulatory review for the next price control period (starting 2014) a two year time period is foreseen starting in 2012 based on the data of 2011.	
Great Britain	Intensive 18 month process initially focused on policy issues but after 6 months detailed company submissions are received which are reviewed. This should allow 12 months to arrive at final regulatory determination 3 months before start of relevant regulatory period. (5 years).	
New Zealand	Under the Customized price-quality path the Commission should make a determination within 150 working days of receiving a complete proposal. These need to be received by the annual cut off date in the Default price proposal. No timescales are set out in the act for the setting of a default price proposal. The previous electricity distribution reset process had a time period of around 15 months from the initial publications to finally publishing a notice in the gazette. However, the intention with default price-quality regulation should use readily available information, which may hasten the process. The next default price-quality path needs to be set in less than 1 year (by 1 December 2009).	
USA	No set timescales are mandated for the process. Rate cases can be initiated by the utility, by an intervener, or by a regulatory commission. Once initiated the process can be completed by a commission order or a settlement agreement, which could occur at any point in the process.	
Canada (BC)	The BCUC has established “timing guidelines” requiring 30 days advance filing before the desired effective date, encouraging expedited filings by ensuring completeness and through pre-filing options, and the processing of filings on a first come – first serve basis. Once initiated the process can be completed by a commission order or a settlement agreement, which could occur at any point in the process. A typical recent ruling was completed in less than 12 months.	

It can be seen that in all markets studied the process of overall Price/Rates Review is both lengthy and extensive.

However, this does not translate into/correlate with the degree of focus within different markets on network utility investment plans and underlying asset management practices, which varies widely. For example, whereas it is a central part of the review process in Great Britain and is also a key focus in both Australia and New Zealand, it is a much more limited focus within German and US regulatory review processes. This reflects the relative network context (e.g., age, replacement expenditure, and need for development) and regulatory focus on detailed drivers versus high level implications for consumers.

In Germany the regulator’s focus on the network utilities’ investment plans and underlying asset management practices is limited. The use of the investment budget mechanism under the current revenue cap regime, which is only applicable for transmission and only for certain

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types of investments¹⁴, is relatively new. Therefore, the process for how the regulator assesses and approves these applications has not yet been published. Replacement asset decisions are made solely by the utilities themselves.

Elsewhere, it will be interesting to see the initial setting of default price-quality regulation in New Zealand and the time period and level of review that is devoted to this activity. The first default price-quality regulation is due to apply to distribution businesses from 1 April 2010. The legislation requires any decision to be published in the Gazette at least four months before taking effect, which gives a publication date of 1 December 2009. This is a tight timescale particularly as the input methodologies have yet to be determined. The ability of distributors to apply for customized price-quality path and the lower number of distributors who will now be impacted by this legislation may make these timescales more achievable as will the aspiration for default price-quality paths to be set using readily available information.

In the US, rate cases can involve all capital costs within the utility, or just the transmission and distribution delivery assets. The focus on investment plans and especially underlying asset management practices varies proportionately with the size and scope of the rate case, since in some cases the capital plans include generation facilities.

This variation in focus and extent of examination of investment plans and asset management practices is examined further in Section 4.4.

4.3.3 Duration of Price Controls

One of the elements that could impact on the degree of investigation of investment plans and especially supporting asset management strategies is the time period for which any regulatory controls are typically set. This is shown in the table below and is focused on what the current legislation will require.

¹⁴ The type of projects allowed under the investment budget mechanism includes expansion/extension or reinforcement related projects only.

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Table 15: Duration of Price Control

Country	Electricity Transmission	Electricity Distribution	Gas Transmission and Distribution
Australia	NEM region – Not less than 5 years. WA – Initially 3 years will be 5 years.	NEM – Normally 5 years, but none set by AER yet. WA – Initial 3 years will be 5 years.	NEM/WA - Access arrangements do not expire but cease to have effect if revised. General rule for the review dates is for commencement date of 5 years after the start of the access arrangement. It is expected that WA will adopt a similar process to the NEM region.
Germany ¹⁵	5 years.	3 years initially (2010-2013) then 5 years.	4 years initially (2009-2013) then 5 years.
Great Britain	5 years.		
New Zealand ¹⁶	New requirements are 5 years. Can be shorter but no less than 4 years for default price-quality path and 3 years for customized price-quality path. Small consumer owned electricity distribution companies will not be subject to a price-quality path.		
USA	No set requirements for the duration of a rate. New rate cases can be initiated by the utility, the commission, or an intervener. In general, rate cases are lengthy and expensive processes that must be economically justified before a utility will initiate one. Utilities with extensive growth may initiate a new rate case every couple of years, while stable utilities may go decades between cases.		
Canada (BC)	New rate applications are initiated by the utility. Revenue requirements and rates are set every year or two years based on a forward test-year (or test-years) basis.		

The consistency across regions with five years being a standard time for a price control suggests that this is seen as a reasonable period to set regulated revenues for and to let the network utilities (subject to varying levels of regulatory oversight) manage their businesses. Again, as for the time period for regulatory reviews above, it is equally clear that the duration of Price Control alone as a factor does not create the different requirements or approaches for reviewing asset management practices.

4.3.4 Use of Third Party Expert Reviews

As demonstrated above, in all of the markets, regulatory reviews are lengthy and intensive exercises. As such it is typical that regulators are unable in isolation to conduct these reviews themselves because:

- 1) They lack the scale of resource required;
- 2) They lack certain specialist technical, economic, financial or legal knowledge;

¹⁵ Note: As Germany makes such a simplistic initial determination of asset replacement expenditure it applies an explicit trigger which reopens the revenue allowance where the network utility deviates by more than 1%.

¹⁶ These time periods are for price-quality paths with which companies are expected to comply rather than formal controls. This is discussed further in the appendix on New Zealand

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- 3) They are at an informational disadvantage to the regulated network utilities;
and/or
- 4) It is helpful to have third party expert endorsement of their regulatory decisions.

The table below indicates whether expert reviews are a key part of the setting the regulatory controls and what form they typically take.

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Table 16: Use of Third Party Expert Reviews

Country	Electricity Transmission and Distribution	Gas Transmission and Distribution
Australia (NEM region)	Yes – latest reviews includes network capex (both historic and forecast), non system capex, forecast opex, service standard and governance.	Yes – latest review includes capex and opex during current periods, review of policies for operational and investment decisions, unit costs, escalators, magnitude of capex and opex forecasts and external factor impacting on businesses.
Australia	Yes – Technical consultant were used in 2007 Access arrangement looking at cost base, capital base valuation and forecasts of capital and operations and maintenance expenditure.	Yes – It is likely that experts report will be required but no access arrangements have been undertaken by the AER.
Germany	Yes – for the current price control external advice from consultants were used for: <ul style="list-style-type: none"> • Benchmarking/efficiency analysis • Cost of capital assessment • Quality of supply • Review OPEX costs, data definition 	Yes – for the current price control external advice from consultants were used for: <ul style="list-style-type: none"> • Benchmarking/efficiency analysis • Cost of capital assessment • Review OPEX costs, data definition
Great Britain	Yes – typically for: <ul style="list-style-type: none"> • Review of capex and engineering opex history and plans • Review of asset management • Review of IT systems • Review/benchmarking of generic opex costs • Cost of capital assessment <p>These are undertaken by an array of expert consultancies.</p>	
New Zealand	Not specified in the Act, but previous experience suggests this will be required as technical reviews were undertaken collectively for the planned distribution business reset process, for the Transpower Settlement and for the authorization for the two gas companies. However, the future extent of these reviews under the new rules is not clear.	
	The Act does state that default price-quality regulation should be done using readily available information which may minimize the future reviews.	
USA	Yes – third party technical experts are typically used on all sides: by the utility, by the commission, and by interveners.	Yes – third party technical experts are typically used on all sides: by the utility, by the commission, and by interveners.
Canada (BC)	Yes – third party technical experts are typically used on all sides: by the utility, by the commission, and by interveners.	Yes – third party technical experts are typically used on all sides: by the utility, by the commission, and by interveners.

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The table demonstrates that in most jurisdictions there is a clear requirement to use expert review for key areas. This is certainly the case in Great Britain. These normally include capital expenditure and as part of this the asset management approach being used by the utilities. It will be interesting to see the extent of third party review in New Zealand for the first setting of the Default Price-Quality paths.

The German regulator makes use of external expertise and it is a key part of the regulatory process. In some instances the regulator may seek external advice for a third opinion on a certain issue and the results of consultancy reports are confidential and used only internally. In 2008, the topic of the cost of capital was subcontracted to an external consultancy company and in addition industry associations also sought external advice.

4.3.5 Transparency of Regulatory Approaches

The degree to which companies' future plans and expenditure reviews are in the public domain varies between countries. As an example, Great Britain and Australia have open processes with the chance for submissions on company plans for the next regulatory period as well as publication of technical reviews and draft decisions leading up to the final decision. This should explain the regulator's thinking during the process and the rationale behind any settlement. However, there will clearly be some confidential information and a series of meetings between the companies and the regulator where sensitive information may be disclosed. Other countries have far more closed decision approaches.

An overview of the transparency of process and the information that is typically available on regulatory approaches is shown in the table below.

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Table 17: Transparency of Process for Regulatory Review

Country	Electricity Transmission	Electricity Distribution	Gas Transmission and Distribution
Australia	<p>Typical process for NSW shows a number of publications/ consultations:</p> <ul style="list-style-type: none"> • Publication of proposal (will have been discussion with the AER and companies) • Public Forum and submission • Draft decision and consultants report with pre-determination conference • Submission and revised proposals • Final Determination <p>A similar process involving publication of the proposal, draft and final decisions and submissions is used in Western Australia.</p>		<p>Process has yet to be tested but expected to see much public information including:</p> <ul style="list-style-type: none"> • Publication of proposal (after pre-consultation discussions with AER) • Submissions • Draft decisions and further submissions • Final decisions <p>It is expected that consultants reports will be used as part of the draft decision and these will be published. Public forums are also likely if the process replicates electricity.</p> <p>A similar process will be followed in Western Australia as it adopts a similar process to the national process.</p>
Germany	<p>The assessment requirements are visible in relevant legislation and supporting industry codes. Furthermore the form of information requirements the German regulator seeks on network utility investment plans is made publicly available. The regulator adopts consultation process together with the industry with a number of interactions before publishing its final decision. Depending on the topic the time frame for reviews and feedback may differ for different network utilities. However, the detailed review process is kept fully confidential on a bilateral basis between regulator and each network utility. Typically the consultation process consists of the following steps:</p> <ul style="list-style-type: none"> • Announcement of the topic at hand e.g. method to determine allowed return on equity and first proposal of the regulator • Feedback and comments from industry and relevant stakeholders • Meetings for discussions • Submission and revised proposals • Final Decision of the regulator. 		

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Country	Electricity Transmission	Electricity Distribution	Gas Transmission and Distribution
Great Britain	<p>Process consists of a mix of public consultations (reports and public stakeholder workshops) and confidential bilateral and multi-lateral meetings between the regulator and network utilities. Full detail is found in Appendix C but is summarized below:</p> <ul style="list-style-type: none"> • Publication of initial policy thinking (public) • Utilities and Stakeholders Forum (public) • Initial Bilateral meetings (confidential) • Release of Business Plan Questionnaires (public) • Further Bilateral Meetings (confidential) • Multi-lateral meetings (utilities only – confidential; wider – public) • Receipt of BPQ submissions (confidential) • Detailed review and Q&A including further bilateral meetings (confidential) • Initial regulatory proposals inc high level data (public) • Further Multi-lateral meetings (utilities only – confidential; wider – public) • Further bilateral meetings and Q&A (confidential) • Final regulatory proposals (high level – public; detail confidential) • Final utility consideration – accept/refer to appeal (public)...to date always accepted 		
New Zealand	<p>The latest settlement offer with Transpower saw publication by the Commission on intent to declare control, proposals to amend settlement offer, technical report, draft and final decisions.</p>	<p>Planned reset process included publication of process paper, discussion paper and 6 technical reports, a methodology paper and submissions made by stakeholders at various stages.</p>	<p>Previous controls for vector and Powerco (Distribution only) included publication of decision and draft decision papers, authorization model, consultant's reports and submission on many issues. In addition a conference was organized to discuss the draft decision.</p>

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Country	Electricity Transmission	Electricity Distribution	Gas Transmission and Distribution
USA	<p>Typical regulatory process is very transparent and involves the following steps:</p> <ul style="list-style-type: none"> • Prefiling notice – to inform the commission and/or the public that the utility is planning on requesting a rate increase. At this point, the utility would supply information as to how much of an increase is being requested, information regarding the type of test year to be used, the date the proposed increase would become effective and/or any other information required by the commission. The prefiling notice can serve to allow the commission to establish its timetable for review and hearing of the case. • Filing of actual rate request – the bulk of the work in any rate case rests in preparing and putting together the actual rate case filing, in many cases using some form of a standard filing package. • Review of filing – commission staff will review the filing and prepare its report to the commission. In states where standard filing requirements are used, the initial task is to ensure that the utility has complied with those requirements. The primary purpose of the review, however, is to identify and review the major issues presented in the case and the utilities position on those issues. The staff must then concur with the utility’s position or develop and support its own position. In order to develop its position in the rate case, the staff will normally perform a field investigation, or in essence, an audit of the filing. Once the staff has completed its review, it will issue a report on its findings and recommendations to the commission. This staff report is submitted to the commission and to the utility, which can review the report, and in some cases, file objections to the staff’s findings and conclusions. • Actual hearing of the case – or in some complex cases a prehearing conference may be held to: 1) group interveners with common causes so as to keep the number of participants involved to a minimum; 2) identify issues which can be agreed upon (or stipulated) by all parties (or at least the utility and the staff) and thus limit the bulk of testimony and debate to the unresolved issues, and 3) set a timetable for hearings and develop the order of witnesses. The actual rate case hearing follows much the same pattern as a legal proceeding. Witnesses are called to give testimony, which is often prewritten in a question-and-answer format and filed in writing with the commission prior to, or at the time of, the hearing. Each witness, upon completion of this “canned testimony,” can then be cross-examined by staff counsel and/or interveners. Normally, the utility’s witnesses will be called and cross-examined before the staff and interveners (if any) present their direct testimony and are cross-examined. The next phase of the hearing is presentation of rebuttal testimony and cross-examination by the utility. At this point, the utility may recall its witnesses to present testimony to rebut issues or points presented by the commission staff or interveners during direct testimony. Following rebuttal and cross examination, the case then involves the filing of briefs which present, in writing, the positions and arguments for each group of participants. Reply briefs which address the arguments presented by other parties can then be filed by any party. The final phase in the case hearing is the presentation of oral arguments by the counsel for each party. These arguments act to summarize the party’s case. • Rendering of decision – A hearing examiner usually hears the actual case and has responsibility for drafting the proposed commission order. It is then the responsibility of the full commission to review and record in the case and either approve or modify the hearing examiner’s decision. Once it is approved, the commission issues the order and serves it upon all parties involved in the case. • Appeals process – Any party which was involved in the rate case proceeding has the right to appeal the decision made by the commission. In some states, the appeal is made to the commission itself with further recourse to the state courts. In other states, the appeals process begins in the state court. In most states, the decision of the regulatory commission can be appealed as high as the state’s Supreme Court. No matter what direction the appeals process takes, the appeal can only be made on the basis of an error in the law. The findings of fact in the case must be accepted by the court as long as they are supported by the evidence of the record. 		

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Country	Electricity Transmission	Electricity Distribution	Gas Transmission and Distribution
Canada (BC)	<p>The Commission's regulatory jurisdiction is defined by the Utilities Communications Act which includes three avenues through which the BCUC assesses utility investment plans. The first avenue is a utility application to the Commission; the second avenue is a generic review by the Commission; the third avenue is a complain filing:</p> <ul style="list-style-type: none"> • Utility Application for a Rate Change – the Commissions review of a utility's application is conducted in the context of current information regarding the long-term plans of the utility, the utility's recent approved capital projects and through public hearings. • Generic Review – the Provincial government may request the Commission to look into a contentious energy issue, such as return on equity regulation. • Complaints – the Commission generally receives two types of complaints related to electricity and natural gas utilities: 1) filings against regulated utilities by other utilities, individuals or groups; 2) filings by utility customers regarding their bills. • Alternative Dispute Resolution – the BCUC has adopted alternative procedures to be used prior to the public hearing in order to improve the effectiveness and efficiency of electricity and natural gas regulation; the Commission uses workshops, pre-hearing conferences, town-hall meetings, and negotiated settlements as alternatives to inquire, assess, and potentially resolve issues related to utility investment plans. • Hearings – utility applications or a Commission investigation into a complaint are typically the two drivers for holding a hearing. • Negotiated Settlement – the BCUC emphasizes the use of negotiated settlements as an alternative dispute resolution process to bring utilities and interveners together to discuss disputed items within a submitted application. • Performance Based Regulation – the two basic approaches for performance based regulation are a price cap approach and revenue cap approach. 		

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As is evident from the table above, there is generally a hybrid combination of confidential and public processes adopted – this is seen in Germany, Great Britain, Australia, and New Zealand with more fully public approaches adopted in the US markets.

As an example of the hybrid approach, the consultation process adopted in Germany allows the industry to provide input and feedback to the regulator on specific topics. Before final determinations or decisions are set in place by the regulator, it enables not only the industry and stakeholders to be part of the process but also facilitates the exchange of information and expertise on certain matters. Normally there are a number of consultation rounds and draft documents before the final decision is published.

The process in the US is also quite interactive and involves a variety of stakeholders. Utilities are allowed to conduct briefings and educational sessions to the regulator staff. Public hearings are conducted. When a rate case is filed, interveners and other stakeholders are an important component. Testimony and rebuttals are filed by all parties and are an integral part of the hearing process.

The key point is that regulators generally make strong efforts to provide guiding policy and decisions visible to wider stakeholders and to engage with these wider stakeholders as part of the regulatory review process. However, inevitably due to the sensitive nature of some of the detailed information, particularly where companies are privately owned and publicly listed on stock exchanges, a substantial amount of detailed discussion, data, assessment and decisions are conducted out of the public gaze either multilaterally or more typically bilaterally between the regulator and the network utilities. This allows more frank disclosure between the network utility and the regulator but also allows any major contentious issues to be debated and preferably resolved without any need for public disclosure.

4.4 Key Asset Management Assessment Techniques Adopted by Legislation and Examples of Application

This section focuses in more detail on the asset management requirements that regulators have on network companies as part of revenue and price controls. The assessment is broken down by country into four main areas:

- 1) **Asset Management Requirements: Tools and Guidance** – this considers the methodologies and tools that the regulators have adopted to drive or support their review of network utility investment plans and underlying asset management practices.
- 2) **Asset Management Focused Activities** – considering both the explicit and implicit requirements on network companies to have asset management plans.

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- 3) **Setting Regulatory Controls** – this highlights the relative importance of asset management practices by indicating if and to what extent asset management practices and/or plans were reviewed in setting the latest regulatory controls.
- 4) **Key Examples of Application of Asset Management Reviews** – providing recent examples of regulatory reviews and the degree to which asset management plans have been part of these reviews.

With one exception, none of the jurisdictions reviewed require compliance with asset management standards and/or require specific asset management practices via legislation or industry governance codes or policies. The exception is New Zealand, where the requirement for an asset management plan is outlined within legislation via the Commerce Amendments Act. An overview of particular standards and policies is given below.

4.4.1 Regulatory Approach in Australia

4.4.1.1 Asset Management Requirements: Tools and Guidance

The National Electricity Rules state that the revenue proposal needs to include total forecast capital expenditures which need to comply with the requirements of the submission guidelines and be broken down for each regulatory year.

A key part of these submission guidelines are the spreadsheets that the transmission companies need to complete and in particular the guidelines on what should be provided for forecast capital expenditure. Some of these guidelines such as the requirement for details of the asset management strategy/plan are not specific. The instructions indicate that much of the information does need to be broken down by project to allow further analysis.

The high-level requirements in the National Electricity rules for distribution are similar to transmission. However, distribution businesses need to comply with the relevant Regulatory Information Instrument (which will include the Regulatory Information Notice) rather than the submission guidelines. These instruments are company confidential and are therefore not in the public domain. However, it is likely that similar requirements will exist to those required for the transmission company.

Consideration of what needs to be in an investment plan can be seen by the AER approach to its first draft determinations for Distributors¹⁷. This document states that the AER's approach to assessment has been to determine and examine whether:

- *their governance frameworks, capital expenses policies and procedures are likely to result in investment decisions, on which the capital expenses proposals are based, that are consistent with the capital expenses objectives;*

¹⁷ NSW Draft Distribution Determination 2009-2010 to 2013-2014

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- *the methods and assumptions used to develop each capital expenses proposal, including demand forecasts and estimates of unit costs, are robust and reflect a realistic expectation of the demand forecasts and cost inputs required to achieve the capital expenses objectives;*
- *estimates of real cost escalators and their application reflect a reasonable expectation of input cost forecasts;*
- *the projects and programs that form part of the regulatory proposals generally reflect the capital expenses criteria, including with respect to their scope, timing and costs; and*
- *the capital expenses programs are deliverable and are therefore commensurate with what a prudent DNSP would require to achieve the capital expenses objectives.*¹⁸

While this is similar to the approach taken by the AER from transmission, the application of the approach is different as the characteristics of distribution networks, particularly the larger number of small projects, is not feasible for the AER to undertake a detailed review of each project. More reliance has therefore been placed on review of the distribution companies' policies and procedures as well as underlying assumptions, which will require a higher level of information. The AER (assisted by the consultant) has also paid more attention to general factors like trends in age, faults and methods (e.g., expenditure modeling) and deviation from historical expenditure.

This reliance on higher level information suggests more detail would be required on the asset management policies and how they have been applied as part of the investment plan.

The AER is now adopting a policy of collecting information on an annual basis with guidelines for what needs to be reported for both transmission and distribution companies and templates for production of information. The information requirements are different for the two types of companies, but include templates for:

- Information on historic capital expenses by asset class;
- Asset aging schedules; and
- Operations and maintenance expenditures.

The intention is that this information will assist in the assessment of future regulatory proposals by the distribution and transmission companies.

¹⁸ The capex objectives reflect the need to meet the expected demand, comply with regulatory objectives and maintain the quality, reliability and security of supply.

4.4.1.2 Asset Management Focused Activities

Explicit Requirements

In Australia there is no particular asset management standard that has been adopted by networks and it seems unlikely that there will be one in the near future. While some networks have adopted the PAS 55 standard, others believe it to be inappropriate. The AER at this stage does not prescribe any particular standard that needs to be followed. Some of the companies are also complying with jurisdictional policies for asset management, which may govern the policies they adopt. The ERA does provide guidance and make reference to the International Infrastructure Management Manual – Version 3.0 2006, which is seen by them as providing a best practice framework for the management of infrastructure assets by small electricity and gas licensees.

In the NEM region, the Transmission guidelines specify an asset management plan. Distribution businesses are issued with Regulatory Information Notices, which specify the requirements. These are believed to require asset management plans, but they are confidential documents. There is no explicit reference in the gas legislation.

In Western Australia there is an asset management requirement for all electricity, gas and water service licensees (except retail and trading) to provide for an asset management system. This is specified in the Electricity Industry Act 2004 and the Energy Coordination Act 1994 and has been turned into a license condition.

The specific requirement for the licensee is to notify the ERA of its asset management system for its distribution/transmission system within two days from the later of the commencement date or from the completion of the distribution/transmission system (i.e., almost from the start of the operation of the network there is a license requirement to have an asset management system in place). The licensee must also notify the Authority of any material change to this system with 10 business day of this change.

In order to demonstrate this asset management system the licensee has a responsibility for reporting on the effectiveness of their asset management system within 24 months of the commencement date and every 24 months thereafter (a time period that can be shortened by the ERA). The report on the effectiveness of the asset management system needs to be undertaken by an independent expert, who needs to be approved by the ERA.

The licensee (and the expert) need to comply with the relevant aspects of the Authority's standard guidelines dealing with the asset management system covering the hiring of the expert, scope of the review, conduct of the review, and results of the review. The ERA has published Audit Guidelines: Electricity, Gas and Water Licenses. This provides a detailed guide on what the auditor should examine when produced the report on the Asset Management System. This requires twelve elements of the asset management system to be rated for effectiveness according to an agreed scale. These elements are:

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- 1) Asset planning;
- 2) Asset creation and acquisition;
- 3) Asset disposal;
- 4) Environmental analysis;
- 5) Asset operations;
- 6) Asset maintenance;
- 7) Asset Management Information System (MIS);
- 8) Risk management;
- 9) Contingency planning;
- 10) Financial planning;
- 11) Capital expenditure planning; and
- 12) Review of the Asset Management System.

It should be noted that the review is backward looking and to consider the procedures in place during the period of the audit. The report can include recommendations which the Authority could decide to serve notice on the licensee to implement by some future date if the approach is not seen as satisfactory. The audit guidelines also allow the ERA to bring forward the date of the next audit and this route was taken after the latest review of Western Power with the next review requested in 19 months rather than the standard 24 months.

In addition to the audit guidelines, the ERA has also published a guide for preparing the financial information component of the asset management plan designed to help smaller licensees. This guide notes that the asset management system should specify the measures being taken by the licensee for the proper maintenance of assets used in the supply or provision of electricity or gas and the construction, operation and disposal of these assets.¹⁹

A key part of the asset management system is the asset management plan. The ERA guide for asset management describes this plan as:

“a plan developed for the management of one or more infrastructure assets that combines multi-disciplinary management techniques (including technical and financial) over the lifecycle of the asset in the most cost-effective manner to provide a specified level of service. A significant component of the plan is a long-term cash flow projection for the activities”

¹⁹ Description taken from ‘A Guide for Preparing the Financial Information Component of an Asset Management Plan’ July 2006 – ERA, Licensing, Monitoring and Customer Protection Division

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This definition is taken from the International Infrastructure Management Manual – Version 3.0 2006. This document is seen by the ERA as providing a best practice framework for the management of infrastructure assets by small electricity and gas licensees.

Implicit Requirements

In the NEM region, revenue decisions for electricity companies are normally based on a technical review of investment, which typically involves examination of asset management policies. The National Gas Rules state:

“Capital expenditure must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice”

Demonstration of this good industry practice is likely to require an asset management plan.

In Western Australia the Access code for electricity states that any capital investment should not exceed the amount that would be invested by service providers acting efficiently in accordance with good electricity industry practice. This good practice requires compliance with laws, codes, etc., and contain asset management requirements.

The gas legislation in Western Australia is being modified to closely match the national gas laws. However, current guidelines for lodging documents do contain the requirements for a process for verification of the future capital expenses forecast, which is likely to require an asset management plan.

4.4.1.3 Review of Asset Management Practices in Setting Regulatory Controls

As previously highlighted, the mainland Australian market is regulated by two regulators; one for the NEM encompassing Queensland, New South Wales, Victoria and Tasmania on the eastern seaboard (AER); and one for Western Australia (ERA). Each adopts different approaches to the review of asset management practices of the network utilities.

AER Practices – latest examples

For electricity transmission - a regulatory review was undertaken on TransGrid’s Capital Expenditure (including asset management) in 2008.

For electricity distribution - a regulatory review undertaken on three NSW distribution companies (including asset management policies) in 2008.

For gas networks - there are no gas examples yet done under new legislation.

ERA Practices – latest examples

For electricity network utilities; the last approved Access arrangement had a technical review that included forecasts of capital and operating expenditure. This review was undertaken from 2004-2006.

For gas network utilities the current draft decision on the South West and Mid West pipeline stated that the Asset Management plan was reviewed by the Director of Energy Safety.

4.4.1.4 Key Examples of Application of Asset Management Review

The review process is currently underway for transmission and distribution companies in NSW. A draft decision was made at the end of November 2008 with a final decision due by April 2009. This is the first distribution regulation determination that is being made by the AER.

TransGrid is one of the companies seeking approval for their transmission plans in NSW. As part of this process a review of TransGrid's revenue proposal was performed, which included assessing the asset management framework and planning processes and how they interact to facilitate prudent and efficient expenditure. An independent view on the effectiveness of these processes was provided in the context of the review noting that at a high-level, TransGrid's asset management process informs around 20% (the non-load driven component) of the entire forecast capital expenses allowance and deals with the need to replace aging and poor performing assets and comply with standards. The asset management process also fundamentally informs the vast majority of TransGrid's operating expenses as at a high level TransGrid state that "*all replacement programs are determined by condition, economic, safety and environmental considerations rather than by age alone*". This finding was supported by the extended assets lives achieved for some major assets.

The consultant's report concluded that TransGrid's asset management process is consistent with good industry practice and employs condition monitoring and condition based replacement triggers to maximize the life of assets. The consultants also examined TransGrid's policies and procedures for its core transmission service provision role and considered these to be well structured and well documented.

The assessment found there was good evidence that the documented asset management process and policies were well implemented within the business. This was achieved based on the documentation presentation and interactions with staff and illustrates the requirement to confirm that documentation reflects actual performance.

Another review was performed for the three distribution companies in NSW and noted that asset management plans were part of the material received. In their review they were considering the adequacy of the distribution businesses' planning process which included the planning criteria, modeling and decision making and adequacy of documentation (which specifically included asset management plans).

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As part of their review the consultants were not looking to endorse or reject specific projects, but to check the reasonableness and efficiency of the aggregate level of expenditure. They noted that the normal objective of this type of project is that the reviewer should be able to:

- Assess the efficiency of the network businesses' expenditure estimates and asset management policies in terms of their match with international practice;
- Take into account a natural level of trade-off between capital expenses and operating expenses;
- Be satisfied that the proposed expenditure, projects and programs are consistent with maintaining, or where necessary, varying standards and service delivery capacity;
- Form an overall strategic view of whether the businesses' proposed levels of expenditure are reasonable and efficient; that is, whether they represent efficient levels for the defined security of supply and service standards; or
- If required, be satisfied that they reflect a transitional path from the present level of expenditure to a more efficient level.

The alignment of asset management policies with international practice is explicit in the first bullet point. In addition, a number of the subsequent bullets require an assessment of the approach to asset management. The consultant also produced a separate report for each of the distribution companies, assessing their asset management approaches against good industry practice, and confirming that the documented approaches matched those observed as being applied.

4.4.2 Regulatory Approach in Germany

4.4.2.1 Asset Management Requirements: Tools and Guidance

Similarly to the US markets, in Germany, the primary focus of the regulatory review process is financial. A data collection template (*Betriebsabrechnungsbogen*) specific for price control purposes is used to collect primarily financial data of the utilities such as operating expenses, data on the assets such as year of commissioning, cost of the asset, asset age, remaining useful life, and depreciation. Appendix B provides an excerpt from this template for illustration on the type of information that is collected.

As the German regulatory environment for incentive regulation is currently at the very early stages, there are certain areas which are still under discussion, especially in regards to the treatment of replacement expenditure under the investment budget mechanism. The German regulator decided upon the TOTEX approach to avoid the problem of substitution. This means the regulator does not differentiate between operating expenses and capital expenses but sets the efficiency factor on the basis of total costs (TOTEX). This also means that the regulator does not consider the investment plans of each individual utility.

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However, the German regulator does publish two separate documents (one for electricity and one for gas) on their website for the application and approval procedures of the investment budget for electricity and gas²⁰. The application form is an Excel file with six worksheets which can be downloaded from the regulator's website. For each individual project the transmission and distribution system owners must complete a separate form. There is a separate file for gas and electricity. The main information in this form consists of:

- Name of the investment project;
- Purpose of the investment;
- Acquisition cost of the investment project;
- Asset life of asset;
- Planned commissioning date of the project; and
- Indication of the criteria that the investment comes under from the criteria specified in the incentive regulation ordinance Paragraph 23.

This information from the Betriebsrechnungsbogen is used by the regulator in calculating and setting the revenue cap for each TSO/DSO. In terms of specific information related to investment plans the regulator does not request this. Nevertheless, some information is required from the TSO/DSO. For example, the regulator has to produce reports on certain topics such as an assessment of whether the new incentive regulation regime has impacted negatively on the investment behavior of the utilities. Information on certain investment projects are collected in case the network operator asks for the approval of an investment budget. As this is the first price control under incentive regulation the concepts for investment planning/asset management have not yet been developed.

4.4.2.2 Asset Management Focused Activities

Explicit Requirements

Germany does not have specific standards required or recommended for asset management policies; nor any other no explicit requirements for asset management.

Implicit Requirements

However, Germany provides an interesting example and while there are no explicit guidelines for the preparation of asset management plans there are instruments in place to promote and secure "efficient" investment of the network in order to abide by the Energy Act. These include monitoring of the utilities by the regulator, by means of regular reporting on the status of the network system and on investment planning behavior. Elsewhere, formal reporting requirements have been discussed. For the purpose of technical information related to assets the utilities are required to report to the regulator on:

²⁰ Leitfaden zu Inhalt und Struktur von Anträgen auf Genehmigung von Investitionsbudgets nach Paragraph 23 Abs. 3 ARegV im Bereich Elektrizität & Gas

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- Detailed technical data for example length of lines and cables / voltage or pressure level, installed transformer ratings;
- Complete survey of the performance and the output of the grid including power and current of each voltage, transmission or pressure level;
- Report of the status of the network;
- Extension and topology of the supplied area; and
- Monitoring of the security of supply including listings of breakdowns, risk management, and other resultant activities.

This information is not used for asset management purposes as such by the regulator but used for monitoring and reporting purposes. For example, in 2008 a report on the German gas and electricity gas market was published by the regulator containing information about the expenditure of the transmission and distribution networks (gas and electricity). However, in future comparisons of network data the regulator could look for explanatory factors, one of which may be the existence and application of asset management plans.

4.4.2.3 Review of Asset Management Practices in Setting Regulatory Controls

In Germany, there is no requirement specified related to asset management.

A data collection template (*Betriebsabrechnungsbogen*) specific for price control purposes was issued by the regulator to collect financial data of the utilities such as operating expenses, data on the assets such as year of commissioning, cost of the asset, asset age, remaining useful life, and depreciation. This is intended to give the regulator an insight into the utilities' technical and financial information as well as operational policy and strategy.

4.4.2.4 Key Examples of Application of Asset Management Review

There is no explicit regulatory Asset Management Policy or procedures for the assessment of investment plans under the current regulation regime in Germany.

However, there are certain reports that the regulator has to produce. One report, which can be related to investment planning, is on the evaluation of network status and network development of the German electricity transmission network providers. The TSOs are obliged to submit information as specified in the Energy Act every two years to the regulator on the status of their networks and any upcoming network development plans.

At present, the regulator does not publish how they assess the information provided by the TSO regarding the status of the network. They also do not assess or scrutinize the TSO/DSO decisions on investments. The level of investment and asset replacement decisions on network infrastructure is purely based on the TSO/DSOs own discretion. The only exception is where new investments impact the level of the allowed revenue cap through the investment budget mechanism under the price control regime. This is explained in more detail in Appendix B. However, in summary, the capital cost components as a result of investment budget related

projects can be added to the allowed revenue, once they are approved by the regulator. This therefore increases the allowed revenue.

4.4.3 Regulatory Approach in Great Britain

4.4.3.1 Asset Management Requirements: Tools and Guidance

In contrast with the US and Germany, Great Britain has a very highly structured and detailed set of information requirements relating to network utility investment plans and underlying asset management practices, including detailed data forms, supplementary questions and supporting guidance for network utilities to complete. The fundamental and central element of this is the Business Plan Questionnaire (BPQ) issued by Ofgem.

An overview of the content (i.e., data sheets) of a Business Plan Questionnaire, issued by the Great Britain Regulator Ofgem, for completion and submission by electricity distribution companies in the ongoing Price Review is provided.

Further examples of the BPQ content is provided in Appendix C. In addition, the initial form of BPQ template issued by Ofgem for the ongoing DPCR5 process (i.e., review of Great Britain electricity distribution businesses for the regulatory period 2010/2011-2014/2015) and the accompanying documents providing guidance on BPQ completion and related commentary can be downloaded from Ofgem's website²¹.

²¹ The BPQ tables, and guidance documents can be found at:
<http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=91&refer=Networks/ElecDist/PriceCtrls/DPCR5>

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Table 18: Ofgem Business Plan Questionnaire Table

Table	Description
T1 - Summary	Network costs forecasts summary, DPCR4 and DPCR5 comparison.
T2 - Total network costs	Network costs overview by building block and by year for DPCR4 and DPCR5.
T3 - Total business costs	Total business costs summary. [to be developed]
LR1 - Demand	Forecast trends in maximum demand and units distributed, forecasts of customer specific connection data and expenditure.
LR2 - Generation	Forecast of distributed generation (DG) connection by type, number of units, MW and associated expenditure. Forecast of expenditure on DG by voltage level.
LR3 - Diversions	Forecast of number of diversions, length, expenditure and customer contributions.
LR4 - General reinforcement	Forecast expenditure requirements to comply with ER P2/6.
LR5 - System utilisation	Forecast of changes in substation utilisation parameters produced by forecast level of expenditure.
LR6 - Fault levels	Forecast expenditure due to fault level issues and forecast effects of this level of expenditure on system measures of fault level issues.
LR7 - DNO discretionary	Expenditure which the does not fit into the other building blocks.
NL1 - Condition based expenditure	Forecast condition based expenditure split by fault and non fault.
NL2 - Condition based QoS	Forecast baseline QoS output measures and fault rates delivered by condition based expenditure
NL3 - Condition based volume	Forecast volume of condition based replacement by asset type.
NL4 - Remaining useful life	Forecast change in percentage of asset base with remaining life expiring within 5 years produced by forecast level of expenditure.
NL5 - QoS (IIS)	Forecast quality of service projects and levels of expenditure targeting IIS output improvements.
NL6 - QoS (non IIS)	Forecast quality of service projects and levels of expenditure targeting non IIS improvements.
NL7 - Major sys risks	Forecast expenditure requirements to alleviate flooding issues, and the effect of this level of expenditure on number of substations at risk. Forecast expenditure on CBDs.
NL8 - Operational IT & telecoms	Forecast expenditure on operational IT and telecoms including projects required due to BT 21st Century.
NL9 - Legal & safety	Forecast expenditure due to legal requirements, including ESQCR.
NL10 - Environmental	Forecast expenditure due to environmental drivers.
NOC1 - I&M	Forecast expenditure on inspections and maintenance by voltage level and asset category and details of inspection and maintenance frequency.
NOC2 - Fault costs	Forecast fault costs, non QoS faults and numbers of unplanned incidents.
NOC3 - Tree cutting	Forecast tree cutting expenditure, overhead network and tree coverage related parameters and details of tree cutting cycles.
NOC4 - Other network costs	Network operating costs not included elsewhere
E1 - Engineering indirects	Forecast expenditure on Engineering indirects by high level direct cost category and proportion of total direct cost expenditure.
C1 - Cost increase	Details of above RPI cost increases.
C2 - Unit costs	Details of new build and replacement unit costs and associated engineering overheads.

Source: Ofgem

In recent years, Ofgem has sought to move from a purely periodic five year review of the network businesses to an environment where comprehensive standardized information is provided on an annual basis regarding the performance of the network businesses against their regulatory allowances. This process is largely confidential but some aspects are made public such as Quality of Service performance, which is collated and issued as a stand alone document.

Ofgem first introduced the annual reporting requirement on electricity distribution businesses as part of DPCR4 (settled 2004) followed by implementation of a similar annual reporting requirement on transmission network businesses (gas and electricity) in TPCR4 (settled 2006) and finally, on gas distribution network businesses in GDPCR4 (settled 2007).

The reporting requirement is essentially the annual completion of a detailed spreadsheet aligned to the Price control's BPQ structure. It seeks to capture all of the key data indicating performance of the network businesses on a year by year basis. This annual process allows a

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picture to develop of how network businesses are performing within a Price Control period against: a) what was submitted to Ofgem for approval in their BPQ submissions; and b) what Ofgem ultimately set as their view of necessary activities and thus, what it used to derive allowed revenue allowances for the network businesses.

4.4.3.2 Asset Management Focused Activities

Explicit Requirement

Ofgem is currently consulting on output measures for transmission (gas and electric) companies relating to network performance, asset condition and risk. One of Ofgem's objectives for these measures, as stated in an Open Letter ²² to the Great Britain distribution network utilities, is to assess effective asset management.

Ofgem has also indicated as part of the latest electricity distribution price control review that output measures will be required and should be part of distributors management of the network. This is likely to include fault rates, indices for the condition of the network and modeled percentage remaining useful asset life. Ofgem has stated that distributors who do not demonstrate or provide output measures will be subject to much more intense regulatory scrutiny in the assessment of their investment plans.

Some simple asset management related performance measures such as leakage rates, customer response time, gas incidents etc., are required, monitored and subject to incentives. However, more sophisticated measures are expected to be developed in the next gas distribution price control review.

In addition to the BPQ and related annual monitoring tools/processes as outlined above (and discussed in depth in Appendix C), there are key aspects of asset management to which Ofgem gives particular attention during investment plan reviews. These elements cover the contextual information, development requirements, investment justification, content and delivery of utility investment plans and underpinning asset management practices.

- **Context:**
 - *Overall Asset Management practices* – the investment plan forms one part of the overall asset management framework. Consequently, across all of the regulated network businesses, Ofgem will closely examine the various asset management frameworks in order to establish confidence in the competence and maturity of asset management in each organization and thus, the credibility of the submitted investment plans.

²² This is stated in an Ofgem Open Letter to the Great Britain distribution network utilities issued in November 2008 and found at:
<http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/DPCR5/Documents1/Open%20letter%20on%20%20DP%20CR5%20process%20051108.pdf>

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- *Asset Data* – this covers each of the primary asset types or categories; equipment volumes; age; asset condition; maintenance history/schedules; replacement costs; etc. Ofgem expects to see comprehensive data regarding the asset base for each company, much of which is requested provided via the BPQ. The more comprehensive, detailed and robust the data, the greater the confidence in asset management capabilities.
- **Development:**
 - *Investment plan process* – underpinning the investment plan is the process from which the plan was developed, detailed, costed and internally approved. This is a key area of focus for Ofgem as it provides assurance (or otherwise) regarding the credibility of the investment plans submitted for assessment for a Price Control period. Typically, Ofgem will be seeking evidence of a centralized, enduring investment planning process with appropriate governance, participation from senior officers and evidence of internal challenge.
- **Justification:**
 - *Asset Health & Risk* – of particular importance to Ofgem, as the Great Britain energy network asset base ages and nears the end of nominal life, is the ability of network business to demonstrate a full understanding of the health (or condition) of its asset base and the associated asset specific risks (environmental damage, network operational failure, danger to individuals). Here, Ofgem seeks the rationale for and evidence of asset replacement requirements rather than reliance on simplistic “end of life” anniversary models. It is also particularly important in the context of a logistical constraint on replacement activity to demonstrate an understanding of how to prioritize such asset replacement to minimize consequential asset related risks.
 - *KPIs/Output measures* – in addition to asset health and risk information an increasingly strong area of focus for Ofgem is the development of Key Performance Indicators (KPIs) and standardized Output Measures to demonstrate the impact of investment on network performance (e.g., customer minutes lost (CML), customer incidents (CIs), network losses, carbon emissions, network availability, etc.). The aim is to ensure an improved understanding of overall network health and risk (to add to that of individual asset health and risks. The presence of such KPIs/output measures and the ability to link these to investments provides greater confidence to Ofgem of justification of investments ex-ante and greater ability of Ofgem to assess the impact of investments ex-post. The

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development of appropriate Output Measures is an evolving field in Great Britain network regulation.

- **Delivery:**
 - *Work volumes and procurement efficiencies* – a key area of scrutiny for Ofgem in recent Price Controls has been a review of the proposed work volumes within investment plans and thus: a) the ability of the network businesses to physically deliver the investment program (outage availability, manpower, equipment, etc.; and b) the effectiveness of the network businesses in procuring assets and turnkey scheme delivery. This relates to issues of credibility and efficiency where Ofgem scrutinizes if companies can actually deliver what has been proposed and whether costs are being minimized through economies of scale and related good practice procurement (commoditization; bulk procurement; options etc).

Implicit Requirement

Over the last few years, Ofgem has promoted the development and adoption of robust asset management policies and particularly the promotion and development of the PAS 55 Asset Management Framework. Ofgem has encouraged Great Britain transmission and distribution utilities to implement asset management policies, frameworks, and practices in line with PAS 55.

The PAS 55 asset management framework is increasingly being adopted by infrastructure companies in different industry sectors worldwide. While Ofgem has not stipulated that Great Britain network businesses must become PAS 55 certified by an independent body, it has strongly encouraged Great Britain transmission and distribution businesses to implement asset management policies, frameworks, and practices in line with PAS 55.

Furthermore, Ofgem has implicitly favored those companies who have been able to demonstrate asset management practices accredited under PAS 55 or demonstrably consistent with PAS 55. This takes the form of greater credence being given to company forecasts and greater likelihood of regulatory settlements for a Price Control being closer to the initial submission by the relevant utility.

Consequently, most Great Britain network businesses now have PAS 55 certified Asset Management Systems and indeed, National Grid, which owns both national gas and electricity transmission networks, as well as some regional gas distribution networks, was the first utility and second company worldwide to be formally accredited with PAS 55 status. National Grid has also applied PAS 55 to its US activities and regards it as its “global standard” for asset management.

4.4.3.3 Review of Asset Management Practices in Setting Regulatory Controls

The Great Britain regulator, Ofgem, is at the forefront of developing international regulatory practices in the area of asset management and its linkage to regulatory submissions. This is driven by a number of factors such as, the aging network and the rapid increase in asset replacement expenditure requested by network utilities in recent years and going forward.

All recent price control determinations have required analysis of network utility investment plans, which requires demonstration of underlying asset management plans and policies to provide credibility to the content of these investment plans.

- **For electricity and gas transmission** – extensive review of asset management practices and their linkage to network investment plans was first undertaken in 2004-2005 for the 4th Transmission Price Control Review.
- **For electricity distribution** – currently a high-level review of asset management practices and their linkage to network investment plans is being undertaken for the 5th Distribution Price Control Review. However, the primary focus is review of output measures Ofgem has required Great Britain distribution network utilities to submit which reflect their asset management and consequential capital expenditures.
- **For gas distribution** – a high-level review of asset management practices and their linkage to network investment plans was first undertaken in 2006-2007.

In general, Ofgem's area of focus is based on their experience and observations gathered since Great Britain network utilities were first privatized in 1990. However, Ofgem has been principally driven, in the context of an aging asset base (towards end of life), by the realization of the issues identified above; and the observed consequences in terms of asset/network health, performance and risk. Thus in recent years, Ofgem has focused their attention on the development of strong asset management practices (and thus consequential investment plans) by the network utilities through a number of initiatives and regulatory incentives. These primarily include, as discussed above, PAS 55 compliance (formal or otherwise) and use of KPIs/output measures. Innovation incentives also form part of Ofgem's philosophy and they now have some five years of operational experience. This has been generally encouraging and innovation forms part of the DPCR5 agenda and there is an expectation that the innovation incentives will be expanded and strengthened.

Ofgem Innovation Incentives

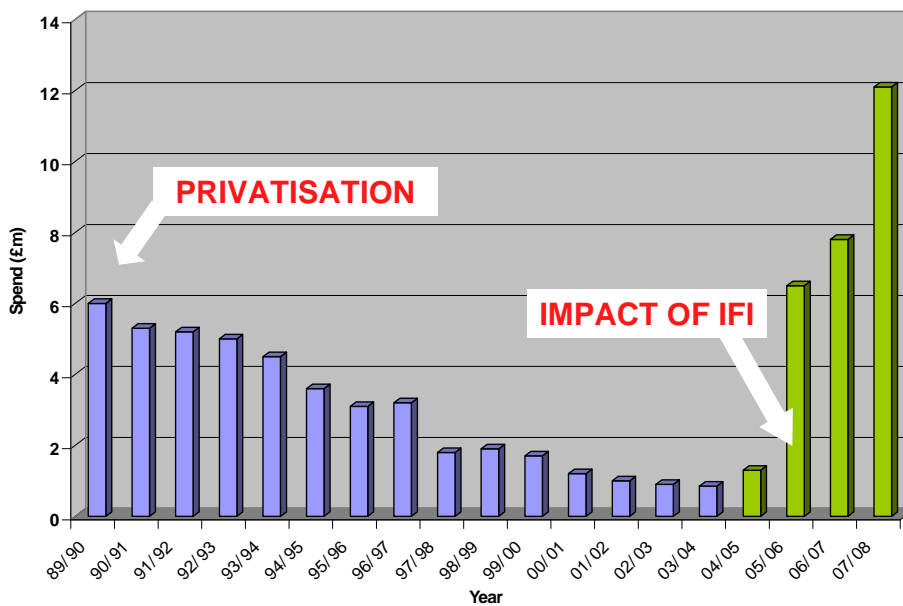
The British experience since privatisation in 1990 has been positive for customers in many important respects. Network costs have fallen by approximately 50% in real terms since privatization, while at the same time the quality of supply has steadily improved. Much of this has been achieved through excellent commercial innovation. However, the investment by electricity distribution companies in engineering Research and Development (R&D) entered a

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progressive decline and by 2002 was approaching zero activity. Interestingly, Ofgem had never withheld R&D funds. Ofgem analyzed the causes of this and concluded that the companies were operating in a rational way, given the regulatory framework. A contributory factor is that R&D is funded as Revenue expenditure and therefore comes under strong “RPI-X” efficiency pressure with a relatively short-term horizon, compared with the lifecycle of typical innovation projects.

To respond to this situation Ofgem introduced two new financial incentives under DPCR4 (commencing 2005). These have now been operating for four years and have been reviewed and extended recently including application to electricity transmission and to gas transmission and distribution. There has been comprehensive supportive feedback from the companies, manufacturers and from academia, and the investment in R&D has already returned to above 1990 levels. The R&D decline and the response to the Innovation Funding Incentive (IFI) for electricity distribution companies are shown in the table below. This is an encouraging picture and shows that well designed adjustment to regulatory frameworks can be highly effective.

Table 19: R&D Response to the Innovative Funding Incentive



Source: Ofgem

Some key aspects of the IFI structure are as follows:

- Ofgem undertook an independent Impact Assessment before introducing this incentive. It indicated a strongly positive net present value. For a projected spend of €38m, the anticipated PV was €160m.
- Ofgem does not determine the innovation program or approve individual projects; projects must comply with a generic good practice guide agreed with Ofgem and in the custodianship of the companies’ Trade Body, the Energy Networks Association, document reference G82.

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- The IFI incentive allows network companies to spend up to 0.5% of their turnover on engineering R&D projects. 80% of their costs are “pass-through” to customers and 20% must be funded by the companies from their own resources. This funding is on a use it or lose it basis. All projects are reported openly each year on Ofgem’s website.
- The present IFI program represents some 180 projects, having a forecast NPV of €70m. No companies have yet spent to their cap, although two are now close to it. A number of companies adopt collaborative working for part of their project portfolio.

Ofgem’s Current Focus

Going forward it is clear that Ofgem’s future focus for regulation/incentivization of asset management practices, which underpin network utility investment plans, is as follows:

- 1) **Consolidation of best practice asset management** – Ofgem will continue to seek further development and improvement of the asset management practices of the network utilities. Having “strongly” encouraged network utilities to adopt practices consistent with (and preferably accredited by) PAS 55, Ofgem will seek widespread adoption of “best practice” processes, tools and techniques by the network utilities and for them to continuously seek to improve.
- 2) **Putting asset management on CEO agenda** – Ofgem is keen to ensure that previous “light” treatment of asset management by network utility executive management and owners is avoided. In particular, Ofgem will seek to ensure that financial objectives do not inappropriately override asset management considerations such that there is an inappropriate impact on asset/network health, performance, and/or risk. In short, Ofgem wants to ensure asset management is a key item on the agenda of any network utility CEO in business planning.
- 3) **Fully understanding asset/network health, performance and risk (KPIs)** – Ofgem believes that many Great Britain network utilities do not yet have a sufficiently good understanding of the health of their assets and/or networks, the performance of their networks, and in particular, the risk (likelihood and/or consequence) they face as a result of network investment (and operating expenses) decisions. Thus, they are clearly focused on ensuring network utilities develop such understanding, especially in the area of risk and furthermore, to develop and use KPIs and output measures to be able to quantify their level of asset/network health, performance and risk as best as possible.

- 4) **Use of KPIs/output measures and linkage to revenues/capital expenses** – In the current network context, Ofgem is being asked to determine whether requested large increases in capital expenses and operating expenses by network utilities is appropriate. They are very keen to establish output measures which demonstrate tangible outcomes for the regulated revenues (specifically the underlying capital expenses) granted. Furthermore, a prime focus of Ofgem going forward is that there is an explicit linkage between the monies that the network utilities seek and spend versus their consequent asset/network health, performance, and risk. This allows Ofgem to move further away from traditional scrutiny of investment plans and subsequent outturn investment versus that proposed at the start of a Price Control period. Specifically, it allows them to demonstrate value for money spent by simply linking revenues to appropriate performance measures and allowing utilities to invest as they see fit to seek to meet their agreed targets for these performance measures. Such explicit linkage between revenues and output measures is being considered for the Great Britain electricity distribution companies under the current DPCR5 process and is expected to be introduced in some form for DPCR5 – though a pure mechanistic approach is thought unlikely until at least DPCR6.
- 5) **Innovation incentives** – Ofgem has innovation as one of its key themes under DPCR5 and, in parallel, has commenced related forward-looking initiatives such as the publication of future network scenarios (LENS²³) and a comprehensive review of regulatory frame works fit for the longer term (RPI-X@20²⁴). The driver for these initiatives is not only the rising investment anticipated for asset management, but also the significant response required to address low carbon targets and a wider environmental agenda.

In an Open Letter (November 2008) to the Great Britain distribution network utilities on the DPCR5 process²⁵, Ofgem indicated that for DPCR5 (the currently ongoing Price Review for electricity distribution companies in Great Britain), output measures will become a key feature of the price control arrangements for a number of reasons:

- Should be the basis of Great Britain electricity distribution companies' management of the network;
- Integral to the assessment of Great Britain electricity distribution companies' historical and forecast costs; and

²³ LENS Long Term Electricity Network scenarios:

www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/lens/Pages/lens.aspx

²⁴ The RPI-Z@20 review: www.ofgem.gov.uk/Networks/rpix20/Pages/RPIX20.aspx

²⁵ The Open Letter can be found at:

<http://www.ofgem.gov.uk/Networks/ElecDist/PriceCtrls/DPCR5/Documents1/Open%20letter%20on%20%20DPCR5%20process%20051108.pdf>

- Ensuring that Great Britain electricity distribution companies deliver – value for money.

4.4.3.4 Key Examples of Application of Asset Management Review

Electricity Distribution

While Ofgem continues to put strong emphasis on the presence of asset management practices aligned to or accredited under PAS 55 in the current Great Britain electricity Distribution Price Control Review (DPCR5), Ofgem added an explicit emphasis on output measures as being a key feature they expect to see presented by the 14 electricity Great Britain distribution network utilities.

In the November 2008 Open Letter referred to above, Ofgem indicated they view output measures as a key feature of the price control arrangements. Thus, Ofgem is seeking to work with the distribution network utilities to agree that output measures and associated targets for DPCR5 are an integral part of the price control process. This will be done on a company specific basis based on the systems and information that is available in each company, although in some areas such as CI and CML, it will continue to be appropriate to have common metrics across the industry. Furthermore, in the Open Letter, Ofgem stated that they are looking for distribution network utilities to commit to a specific package of measures as part of the price control settlement, including:

- | | |
|-------------------------------------|---|
| Overall customer performance | <ul style="list-style-type: none">– Number and duration of interruptions– Customer satisfaction with the DNO |
| Load related spend | <ul style="list-style-type: none">– Connection or customer driver– For highly loaded substations, number of customers at risk, potential time at risk, extent of load growth– Asset utilization |
| Non load related spend | <ul style="list-style-type: none">– Fault rates– Indices for the condition of the network– Modeled percentage remaining useful asset life |

Source: Ofgem

Ofgem’s emerging approach on output measures is explicit, in contrast to the implicit indications Ofgem has previously provided regarding the influence of PAS 55 aligned asset management practices on its view of network business investment plans. Specifically, it has explicitly indicated that under its conducting of DPCR5 those distribution network utilities that do not satisfactorily demonstrate or provide proposed output measures to Ofgem will be subject to much more intense and less favorable regulatory scrutiny in the assessment of their investment plans among other things.

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As part of DPCR5, Ofgem is looking for distribution network utilities to commit to a company specific package of output measures that reflect what the distribution network utilities already measure internally. They have indicated they will not set out their own views on the level of risk that distribution network utilities' plans will generate, as this is for companies to decide. However, Ofgem has clearly indicated that they will want to be reassured that the output measures are consistent with the capital expenses plan each distribution network utilities is putting forward.

Ofgem very recently outlined two different types of deals that distribution network utilities could expect based on whether Ofgem determines that as part of their regulatory submissions they provide well-defined outputs (Type 1) or limited outputs (Type 2). Ofgem has indicated they expect all distribution network utilities to aim for a Type 1 settlement (even if Ofgem subsequently determines a Type 2 settlement is more appropriate for one or more distribution network utilities). An overview of the nature of the regulatory settlements under each of the Type 1 and Type 2 conditions is outlined below.

Type 1 Settlement – Well Defined Outputs	Type 2 Settlement – Limited Outputs
Common base cost of capital	
Challenge to DNO forecasts	Extra challenge to forecasts
Tightly defined outputs which are measureable and verifiable	More limited output information; greater use of CI, CML and fault rate; use of some input measures
High powered incentive scheme	Lower powered incentive scheme
Easier to reach high returns based on verifiable performance against costs and outputs	More difficult to obtain higher returns
Limited scrutiny of under-spend as long as output measures are met	More intrusive scrutiny of any under-spend against capex allowances (<i>and even scrutiny if no under-spend</i>)
	Ex-post review of capex (three pots treatment)
Common CI and CML incentive rates (Ofgem will consult on this in December) and common standards of performance	

Source: Ofgem

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Electricity and Gas Transmission

In the last Transmission Price Control Review (TPCR4) conducted in 2005-2006, Ofgem, for the first time, applied a complete top-down and bottom-up assessment of investment plans and underpinning asset management processes relating to asset volumes and costs. (Previously, only a bottom-up analysis had been undertaken and there had been no focus on asset management practices.) The application of this holistic approach is illustrated below:

	Volumes	Costs
Top-Down Approach	Review Aspect: Asset Replacement Modeling Key Issues: Asset Lives Review Method: Workshops, Q&A, review of company modeling, Ofgem’s own modeling, benchmarking, third party expert knowledge	Review Aspect: Unit Costs Key Issues: Equipment + Other Factor costs Review Method: Workshops, Q&A, review of forecast model, scheme assessment, benchmarking, third party expert knowledge
Bottom-up approach	Review Aspect: Asset Condition Assessment Key Issues: Need (evidence) and granularity Review Method: Workshops, Q&A, review of asset management practices, scheme assessments, site visits, third part expert knowledge	Review Aspect: Scheme Costs Key issues: need, design choice and costing Review Method: scheme assessments, benchmarking, third party expert knowledge, Q&A, Workshops

As a result of this, Ofgem was able to gather sufficient insight and evidence to support its determination of appropriate levels of capital expenses, and consequentially regulated revenues for each of the Great Britain transmission owners. While it is not possible to divulge details due to data confidentiality, KEMA can indicate that example outcomes of this approach were:

- For one transmission owner the need case for asset replacement for certain key asset types on an asset-by-asset basis was determined to not be adequately proven and thus subject to volume related reductions in capital expenses allowance of up to 20% against their submission.
- For another transmission owner, the results of Great Britain and international benchmarking indicated proposed unit costs were not comparable with other utilities (on a like-for-like normalized basis) and thus saw cost based reduced allowances of up to 25% in different asset areas against their submission.
- For a third transmission owner, scrutiny of their asset replacement modeling and comparison with best practice techniques suggested the need case for asset replacement for certain key asset groups was determined to not be adequately proven and thus subject to volume related reductions in capital expenses allowance of up to 25% against their submission.

The holistic approach above is expected to remain a central part of future Transmission Price Control Reviews.

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Looking forward, similar to the case for distribution, output measures are also set to become a key feature of regulation of transmission network utilities and impact on their regulated revenue streams. Based on a formal commitment they required the Great Britain (electricity and gas) transmission owners to make at the time of setting the current Price Control, Ofgem is also in the process of introducing output measures for transmission by 2010. Ofgem's stated main objectives for developing transmission network output measures are to enable it to:

- **Assess effective asset management** – i.e., to identify measures that will allow Ofgem to better assess the efficiency of historic and forecast capital expenses with a focus on the replacement and the maintenance of network assets to ensure that the actual forecast network risk profile is within acceptable bounds.
- **Understand network performance** – if possible, to improve the measures of network performance that impact consumers which have a clearer interaction with network investment.
- **Develop comparative analysis and sharper incentives** – the development of output measures should enable Ofgem to compare the performance of transmission and distribution companies. The benefits of comparative analysis have already been demonstrated in gas and electricity distribution and in other sectors, such as water. In addition, the measures may help Ofgem to target incentives on specific aspects of performance.
- **Provide greater information to network users** – developing output measures should also reveal more information about network capability at present and in the future. This will inform users' decisions regarding network access or capacity arrangements.

The areas for which Ofgem is seeking to identify and apply output measures and thus to enable evaluation of, are:

- Network asset condition;
- Network risk;
- Network performance; and
- Network capability.

As yet, there is no direct linkage between output measure performance and regulated revenues, but by introducing it within this current Price Control period, Ofgem clearly intends to gather performance data with a view to creating such linkage for the next Price Control period commencing in 2014-2015.

4.4.4 Regulatory Approach in New Zealand

New Zealand is a relatively small electricity market with less than two million customers. It has been liberalized for many years with separation between generation, transmission, retail

and distribution and supply. There is strong vertical integration between the generation and retail parts of the industry, but this integration is restricted between distribution and generation and prohibited between distribution and retail sectors. In 2008 there were some major amendments to the Commerce Act which governs how electricity lines and gas pipeline businesses are regulated. The implications of these upcoming changes to the regulatory structure will be an important part of findings for this jurisdiction.

4.4.4.1 Asset Management Requirements: Tools and Guidance

In New Zealand, the agreement of regulatory expenditure through the price-quality path relies heavily on the information disclosure that all the network business will be required to undertake. Additional information can be requested and provided as illustrated in the Authorization undertaken for Vector and Powerco and the request used to obtain additional information from the distributors as part of the abandoned reset process. However, it does appear that a lot of the required information is extracted straight from the information disclosures and that is expected to continue in the future with the stated aim for default price-quality paths to be set in a relatively low cost way using readily available information.

The Commission does not intend to determine new information disclosure requirements until applicable input methodologies have been developed. All information requirements determined prior to the new Act therefore continue to apply to network companies. In the case of electricity this consists of:

- Electricity Information Disclosure Requirements 2004 (including all amendments to October 2008);
- Electricity Information Disclosure Handbook; and
- Handbook for Optimal Deprival Valuation of System Fixed Assets.

In addition, for electricity distribution companies, they also need to comply with the Electricity Distribution (Information Disclosure) Requirements 2008. Key areas that the distribution businesses are required to report on include:

- Financial statements;
- Asset valuations;
- Prescribed contracts;
- Financial and efficiency performance measures; and
- Asset management plans.

A similar list applies to Transpower, but without Asset Management plans and includes some additional criteria such as energy efficiency measurements, reconciliation reports and pricing methodologies.

There is a specific requirement that all disclosures need to comply with the Electricity Information Disclosure Handbook. There are also schedules that indicate the forms that need to be completed and Certificates that need to be signed by Directors of the business.

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The Gas (Information Disclosure) Regulations 1997 will continue to apply to gas pipeline companies until the Commission makes a determination on the new information requirements. Key requirements for disclosure (as of September 2007) include:

- Financial statements;
- Prescribed agreements;
- Wholesaling activities;
- Financial and efficiency performance measures;
- Energy efficiency performance measures and statistics;
- Reliability performance measures;
- Pricing methodologies;
- Methodologies for allocation of costs, revenues;
- Pipeline capacity disclosures; and
- Line charges.

There is a requirement for financial information to be certified by an auditor and other key information to have a certificate signed by Directors of the company. It is unclear what additional information will be requested from gas pipeline companies for the calculation of a default price-quality path.

The evidence from the Vector/Powerco Authorization was that the consultants did request significant information on the capital expenditure and asset management strategy of the two companies. It is unclear whether a similar level of information would be required for a default price-quality path.

4.4.4.2 Asset Management Focused Activities

Explicit Requirements

New Zealand does not have specific standards required or recommended for asset management policies.

However, at the highest level the Commerce Amendment Act makes two specific asset management requirements:

- 1) The first requirement is part of the information disclosure requirements, which specifically states that an asset management plan is required.
- 2) The second requirement relates to the content and timing of price-quality paths. It states that a price-quality path must include incentives for an individual supplier to maintain or improve its quality of supply and those incentives may include special reporting requirements in asset management plans, if the supplier fails to meet the quality standards.

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New Zealand Electricity Distribution businesses need to publicly disclose an asset management plan in line with the Electricity Distribution (Information Disclosure) Requirements. This handbook lays out the process that needs to be followed in the production of this plan. It is expected that electricity business will implement best practice asset management processes.

The handbook provides a description of the mandatory content of the asset management plans of:

- **Summary** – brief overview and key information.
- **Background and Objectives** – including purpose of the plan, interaction with other objectives, periods covered by the plan (which must be at least 10 years), date of approval by the board of directors, descriptions of stakeholders interests, descriptions of accountabilities in the distribution business and details of the asset management systems and process including asset management systems/software and Information flows.
- **Assets covered** – description of distribution area, network configuration, network assets by category, justification for the assets.
- **Proposed service levels need to include** – customer orientated performance targets, other targets relating to asset performance, asset efficiency and effectiveness and efficiency of the distribution business. In addition, justification for these service levels should be included.
- **Network Development Planning** – planning criteria and assumptions, prioritization methods, demand forecasts, distributed generation and non-network solutions policies, analysis of network development options and selected program.
- **Lifecycle Asset Management Planning** – description of maintenance planning criteria and assumptions, routine and preventative inspection and maintenance policies, asset renewal and refurbishment policies, asset replacement and renewal expenditure.
- **Risk Management** – methods, details and conclusions of risk analysis and details of emergency response and contingency plans.
- **Evaluation of Performance** – progress against plan (physical and financial), comparison of actual performance against targeted objectives and a gap analysis and identification of improved initiatives.
- **Expenditure Forecasts and Reconciliation** – forecasts of capital and operating expenditure for minimum 10 years period and reconciliations for the most recent year that is available. The asset management forecasts for the first five years need to be disclosed with other financial statements and audited.

The asset management plan needs to be approved by the Board of Directors and present forecasts in current \$NZ terms. All significant assumptions need to be clearly identified in the

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plan which also needs to be published and publicly disclosed. In addition to the plan, companies in New Zealand also need to report on expenditure forecast and reconciliation based on the most recent and previous asset management plans.

The Electricity Transmission Company is subject to the Electricity Governance Rules and Regulation (part F) as part of regulation by the Electricity Commission. This specifically requires a comprehensive plan for asset management to be produced as part a Grid Upgrade Plan. However, there is no specific requirement from the Commerce Commission for asset management.

No specific requirements for asset management plans for gas are included in the current information disclosure requirements. However, they are covered by the Commerce Amendment Act requirements.

Implicit Requirements

The purpose of the Commerce Amendment Act is to *promote the long-term benefit of consumers... such that suppliers of regulated goods and services:*

- 1) *have incentives to innovate and to invest, including in replacement, upgraded and new assets;*
- 2) *have incentives to improve efficiency and provide services at a quality that reflects consumer demands;*
- 3) *share with consumers the benefits of efficiency gains in the supply of the regulated goods or services, including through lower prices; and*
- 4) *are limited in their ability to extract excessive profits.*

The incentives to innovate and to invest, while at the same time requiring efficiency incentives and avoiding excess profits, would suggest the need for an asset management plan to justify any investment. This is brought out more specifically in Commerce Commission discussions on information needed to demonstrate different forms of efficiency.

4.4.4.3 Review of Asset Management Practices in Setting Regulatory Controls

For electricity transmission, an input into the decision not to impose control on Transpower was a review of the company's capital expenditure plan including asset replacement, refurbishment, and enhancement undertaken in May 2007.

For electricity distribution, the planned reset process had a technical assessment in 2007 of Distribution Networks and their asset management practices.

For gas networks, there is no transmission control yet set, but as part of the control placed on Vector and Powerco's distribution business, a detailed review of the capital expenditure was

undertaken by a technical advisor in 2007 and 2008. This included an assessment of the asset management plans.

4.4.4.4 Key Examples of Application of Asset Management Review

Electricity Distribution

Due to the introduction of new legislation, the electricity distribution price-quality thresholds have not been revised since 2004. However, a process was begun in 2007 to look at revising these for 2009. Although subsequently suspended the approach does suggest what the Commerce Commission believes will be important in future decisions.

As part of the Threshold Reset process the Commerce Commission ordered six consultants reports, including an assessment of “Distribution Networks and Asset Management.” This information was provided as part of the normal Information Disclosure process in addition to a notice issued to the Distribution business requiring information on their investment plans and asset management strategies.

This report had identified that a number of the distribution businesses could require moderate renewal increases in the 2009-2014 period and more significant increases in the 2014 regulatory period. One option being promoted by the Commission was the introduction of an additional incentive factor to the price-path threshold. This would allow increased notional revenue for distribution businesses having significant renewal investment plans. This was not considered necessary for the 2009-2014 period, but was more likely to be required in the following regulatory period. Where individual distribution businesses did have additional investment requirements during the 2009-2014 period it was considered that these should be addressed through customized thresholds.

These customized thresholds were planned for development during 2009 and implementation during 2010 before the suspension of the process. However, the option of customized price-quality paths is a key part of the new legislation for the larger non-consumer owned distribution networks.

Gas Distribution Businesses

In 2005 the Minister for Energy announced that he was imposing controls on two gas distribution businesses (Powerco and Vector). Setting this control was a long process and required a detailed review of the companies’ proposed capital expenditures by a technical expert. Due to the information asymmetry between the Commission and the businesses the Commission has not sought to decide what investments the businesses should make for controlled services. Instead, it has carried out an assessment of the proposed capital expenditure forecasts so that to the extent practical only efficient investments are provided for on an ex ante basis. This includes an assessment of the demand forecasts of the two companies.

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In the technical expert's preliminary expenditure review they undertook a top-down approach using international benchmarks (Australian distributors) of distribution spending and a bottom-up approach assessing the components of the proposal for their efficiency and reasonableness. The recommendations of the Commission were predominately based on the bottom-up approach given that this is the first control period and that capital expenditure requirements can vary from year to year. This review also considered a high-level assessment of the asset management plans of both businesses.

The technical expert initially recommended large cuts particularly to the capital expenditure plan of Powerco and a smaller cut to Vector. This reflected a significant increase in the level of capital expenditure requested by Powerco with insufficient information to justify this expenditure. However, the draft decision noted that they had been hampered by poor information and that this could be substantially revised.

Vector did provide some information to fill the gaps and made some relatively minor adjustments. Powerco provided a different set of proposals with different supporting information that included a large increase in their planned investment for the 2008-2012 period. The technical expert concluded that the additional information provided by Powerco made it impossible for them to make recommendations on a bottom-up approach and therefore adopted an Alternative Review Method for considering the proposals. This entailed a review of historical expenditure levels including the 2007 actual and 2008 budgeted expenditure to gain a sound baseline of expenditure for 2002-2012.

The end result of this re-examination was an increase in the recommended capital expenditure of both companies, but still less than the required amount. The technical experts recommendation for Powerco was a significant reduction including a suggestion (not accepted by the Commission) that some of this expenditure should be ring-fenced and recovered on an ex-post basis. The Commission was concerned that this outcome could be perceived as rewarding poor information, but noted that, in the latter part of the Authorization process, Powerco has attempted to provide the Commission and its advisors with better information.

The building block approach (including analysis of expenditure) has resulted in allowed revenue for 2008-2012 for each of the distribution businesses. This is translated into a regulated price path using a CPI-X weighed average price cap. For the purposes of implementing the initial price changes required as part of this Authorization there was also a need for a P_0 reduction that took effect from the 1 January 2009.

4.4.5 Regulatory Approach in the US

4.4.5.1 Asset Management Requirements: Tools and Guidance

In the US, the focus of regulatory attention is to structure rates that are sufficient, but no more than sufficient, to allow gas and electric utilities to cover their operating and capital costs, to attract needed capital and to maintain their financial integrity, and yet provide appropriate

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protection to the relevant public interests. The basic standard of rate regulation is the revenue requirements standard, which provides revenues that allow a utility to cover operating costs and earn a reasonable rate of return on property devoted to the business. The determination of required revenue involves the determination of three major items: 1) allowable operating costs; 2) net value of the investment in property; and 3) a fair rate of return.

Operating costs are calculated using “test year” information from a recent or projected 12 month period, adjusted as necessary. The net value of investment in property is referred to as the “rate base” and represents the capital of the company upon which a rate of return should be applied. This rate of return is determined by the regulatory agency and applied to the rate base to provide a fair return to investors.

To determine a rate of return on rate base that is appropriate for the overall cost of capital, the commission first identifies the components of the company’s capital structure. The cost of each capital component is then determined and weighted according to its proportion of total capitalization. These weighted costs are summed to determine the overall cost of capital, which becomes the allowed rate of return on rate base. Capital programs must typically be documented in the filing package to be included in the capital structure. This documentation must include a description of the program, costs and benefits.

Many states utilize some form of standard filing package which must be used by a utility whenever it files for a rate increase. The use of a standard filing package allows the commission staff to review the rate request based on the facts presented while not having to determine if all the facts are present. It is important that the utility present its request and issues based on complete information, because, as a legal proceeding, the case will be decided based on the facts on record (“findings of fact”).

Asset operating and maintenance (O&M) costs are reflected in test year information, not in the capital calculation. Standard filing requirements typically require that a utility file a recent Cost of Service Study (COSS) to determine costs to serve various classes of customers. This study captures operating costs for assets required to provide the service, and is used as an input to establishing different tariffs.

In determining the appropriate treatment of costs incurred by a company, the commission must consider whether the company's actions, which results in such costs, are prudent. In deciding whether the actions of a utility are prudent, commissions apply the "reasonable person" standard; that is, the standard of care a reasonable person would exercise under the same circumstances confronting the management of the utility at the time of the decision to take such actions.

The proper analysis for determining any type of economic sanction such as a disallowance of recovery for imprudent or unreasonable actions on the part of a regulated utility occurs in several steps. First, there must be a clearly understood definition of the standard of care by which a utility's performance can be measured; second, the actions of the utility must be

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examined to determine if there has been a failure on its part to conform to the standard required; and finally, there must be a reasonably close causal connection between the imprudent conduct, if any, and actual loss or damage. Actions by regulated public utilities which are found to constitute imprudent management that result in increased costs are generally disallowed.

4.4.5.2 Asset Management Focused Activities

Explicit Requirements

The US has not adopted any particular asset management standard and seems unlikely to do so in the near future. Instead, regulators rely greatly on benchmarking activities to determine performance levels relative to industry averages.

There are also no formal requirements in the US in the regulations that currently specify the requirements for an asset management plan, however, individual regulations often deal with items that would typically be associated with a plan, including asset performance, maintenance and replacement requirements. These items are dealt with on a case-by-case basis within the plans submitted by a utility in their filings for a rate case.

Implicit Requirements

While not explicitly stated, the fundamental process of establishing an allowed rate of return on a rate base encompasses all the elements of asset management. Typical considerations in determining both the rate base and the allowed return include the performance of the assets, the costs and risks involved, and the prudence of management actions.

4.4.5.3 Review of Asset Management Practices in Setting Regulatory Controls

In the US markets, while asset management is not explicitly referenced as practice, the review of utility operations involved in a rate case proceeding involves a thorough evaluation of asset costs, performance, and risks. Capital investment plans are analyzed in significant detail and assessments are made regarding their necessity, projected results, financial impacts, and strategic value. Operating costs are similarly assessed and compared with performance results. Commissions often order specific asset replacement programs or maintenance practices, and require utilities to report progress against these orders.

4.4.5.4 Key Examples of Application of Asset Management Review

Due to the number of jurisdictions and corresponding number of different rate cases, it is difficult to select a single proceeding as representative of how asset management plans impact regulatory decisions in the US. Different state commissions operate with varying degrees of sophistication, funding, resources, and working relationships with the utilities they regulate. However, a recent ruling by the State of Connecticut Department of Public Utility Control regarding Connecticut Light and Power Company does reflect a typical process and provides

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greater-than-average insights into the methodology that was followed, the evaluation process used for assessing asset plans, and the reporting requirements that were specified.

On 30 July 2007, The Connecticut Light and Power Company (CL&P) filed a request to amend its rate schedules with the Department of Public Utility Control (DPUC). CL&P proposed to increase capital spending to address reliability, safety, and power quality issues within its distribution infrastructure. They stated that the capital program, together with maintenance and tree trimming expenses, was the minimum necessary to avoid a decline in reliability levels provided to its customers. CL&P further stated that, if it did not proceed with spending in these areas, statutorily-mandated reliability levels would not be met and customers would become further dissatisfied with the quality of electric service. The Company's distribution capital spending program was comprised of 26 initiatives.

The DPUC reviewed each initiative in detail and determined that each one was necessary and reasonable to maintain system reliability and safety of the public and employees. The DPUC noted that certain issues materially warrant increased spending on distribution system infrastructure. Additionally, since the last decision in 2002 several major plant material condition-related issues had come before the DPUC. In each of these cases the DPUC determined that certain equipment was in need of redesign and/or replacement, and required that CL&P take action to remediate the condition over the following several years.

The DPUC also examined issues related to reliability and the material condition of CL&P's plant through two proceedings: the annual Transmission and Distribution Reliability Performance (TDRP) proceeding and the Line Maintenance Plan proceeding. The DPUC concluded that CL&P's reliability as presented in the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) was higher as of year-end 2006 than 1998 levels. Reliability improved substantially during the years 1998-2001, but did not improve since that time. Based on this analysis, the DPUC believed an increased capital program was necessary to avert a decline in reliability. While recognizing it was essential to balance the competing interests of ensuring adequate quality of service to customers and the rate impact of the increased spending necessary to achieve such service levels, the DPUC concluded that the expanded capital needs were warranted by the need to support reliability and safety discussed above. The DPUC, therefore, approved the capital program expenditures, subject to adjustments.

They ordered the company to report annually on the status of its capital spending as follows: by November 30, with a budget/forecast of spending by initiative or category for the following year; and by March 31 of each year showing actual spending by initiative or category for the preceding year. The DPUC recognized that plans might change for good reasons over the next two years. Accordingly, if the budgeted amount for any initiative or category changed by more than 10% from that represented in the proceeding, the company must provide an explanation in the annual budget report due November 30. Further, if actual total spending varied from budgeted spending in any year, CL&P must provide an

explanation in the annual spending report due March 31 of each year. If capital spending deviated substantially from the forecast, the DPUC would reopen the decision and conduct an investigation.

4.4.6 Regulatory Approach in British Columbia, Canada

For rate regulation, the British Columbia Utilities Commission (BCUC) uses a “future forecast” methodology to review utility expenditures. Utilities apply for rate increases prospectively for “forecast test year periods” of one, two, or three years. Total revenue requirement is determined by the BCUC and is then divided by annual forecast sales volume for the forecasted test year in order to get an average rate a utility may charge. The utility’s rate tariff is amended to adopt the new rate. In determining revenue requirements, the Commission examines the utility’s rate base, and or assets the utility may make a return on. The Commission may disallow certain costs in an application if they are deemed not reasonable or prudent.

4.4.6.1 Asset Management Requirements: Tools and Guidance

The British Columbia Utilities Commission (BCUC) requires a complex variety of information in assessing utility investment plans. In general, utilities are required to present revenue requirements and rate design in a set of regulatory schedules in applications and in annual public reports. Long-term information requirements are described in utility integrated resource plans (IRP) which include rate base information linked to depreciation and amortization and return on equity and total annual revenue requirements. In the immediate to short-term, the information required for the issuance of certificates of public convenience and necessity offer an opportunity for the Commission to make determinants for new, expanded, or refurbished asset investments by utilities.

Beginning in May 2003, the BCUC began requiring public utilities to file additional information in order to pursue the goals of the 2002 BC Energy Plan. The information requirements for public utilities in BC to submit to the BCUC include:

- An anticipated capital expenditures plan over a period specified by the Commission;
- A plan to meet demand for energy via acquisition and the expenditures required; and
- A plan to reduce demand for energy and expenditures required for that purpose.

A prime example of the new Commission information requirements is the submission of an Integrated Electricity Plan (IEP) and Long-Term Acquisition Plan (LTAP) on a four year cycle. The IEP provides a 20-year outlook that includes 20-year load resource balance forecasts, resource option analysis to meet future loads with characterization of demand-side and supply side options, alternative resource portfolios, and an examination of

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cost/risk/social/and environmental in portfolio evaluation. The LTAP is a 10-year plan that covers resource mix, demand-side management, potential future resource options, asset management of power generation, and security of supply.

Additionally, electric utilities submit a Resource Expenditure and Acquisition Plan (REAP) that details short-term plans (2-4 years) as part of the Integrated Electricity Plan. The REAP is resolved via a negotiated settlement. REAP includes the following general items:

- Planned Capital Expenditures on capital projects, resource acquisition, and demand-side management;
- Anticipated Energy Demand; and
- Utility Plan to reduce energy demand of its customers.

In May 2008, the government enacted Bill 15, the Utilities Commission Amendment Act (UCA) of 2008, which required public utilities to file long-term resource plans with more definitive and specific information regarding demand-side measures and explanations regarding why energy demand is being met with new facilities and purchases and by demand-side measures.

The BCUC has published a number of guidelines for utilities to utilize towards the cost effective delivery of secure and reliable energy services. The Resource Planning Guidelines assist utilities with identifying, forecasting, selecting and evaluating resource plans. The Utility System Extension Guidelines provide ten guidelines for system extensions, or extension tests.

4.4.6.2 Asset Management Focused Activities

Section 45 of the UCA was amended in 2003 to expand and clarify the planning requirements of utilities and the Commission's role to review filed plans to determine whether expenditures are in the public interest and whether associated rate changes are necessary and appropriate.

The additions are as follows:

- A public utility must file the following plans with the commission in the form and at the times required by the commission:
 - 1) A plan of the capital expenditures the utility anticipates making over the period specified by the commission.
 - 2) A plan of how the utility intends to meet the demand for energy and expenditures required for that purpose.
- After receipt of a plan filed under the above, the commission may:
 - 1) Establish a process to review all or part of the plan and to consider the proposed expenditures referred to in the plan.

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- 2) Determine that any expenditure referred to in the plan is, or is not at that time, in the interests of persons within British Columbia who receive, or who may receive, service from the public utility.
- 3) Determine the manner in which expenditures referred to in the plan can be recovered in rates.

4.4.6.3 Review of Asset Management Practices in Setting Regulatory Controls

Investment plan requirements occur within the context of the current long-term plans of the utility. Key aspects of investment plans revolve around certificates of public convenience and necessity, rate regulation, return on equity, and rate design. Certificates of Public Convenience and Necessity applications are required for utilities to demonstrate the cost-effectiveness of planned infrastructure investment and that the investment is in the public interest.

Rate regulation must justify revenue requirements associated with the primary costs of operating the utility. Investment plans must plan for the following costs:

- Cost to build, operate and maintain the utility's facilities;
- Cost to finance debt incurred from building facilities;
- Depreciation and amortization expenses;
- Costs of financing debt generally; and
- Return on shareholder's equity including the resulting income taxes.

The rate design analysis criteria used by the Commission requires utility investment plans to use the following principles in their submission of rates:

- Simple and understandable to the customer;
- Cost-based, or tied to actual services provided;
- Efficient;
- Stable and predictable; and
- Non-Discriminatory.

Return on Equity and the Allowable Return on Equity are key components of a utility's investment plan. The general methodology of the BCUC is to forecast the risk-free rate of long-term Government of Canada Bonds and then determine a specific risk-premium for each energy utility within British Columbia. The ROE percentage is the composite of the risk-free and risk-premium percentages.

4.4.6.4 Key Example of Application of Asset Management Review

The British Columbia Hydro Power Authority (BC Hydro) and British Columbia Transmission Corporation (BCTC) entered into an Asset Management and Maintenance Agreement in May 2003. Article 3 of the Agreement delineated the engagement of BCTC to

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manage and maintain the Transmission System for BC Hydro. The agreement included recognition that BCTC must “manage and maintain the Transmission System to meet all requirements of the Commission, including requirements relating to safety and reliability, and to manage and maintain the Transmission System to meet any applicable requirements of the Western Electricity Coordinating Council and other applicable industry standards”. Article 3 explicitly lists the following asset management requirements for BCTC:

- Capital Replacement Programs and carrying out capital upgrades and additions;
- Monitoring and assessing useful life of assets forming part of the transmission system;
- Identifying significant operating capacity limitations or constraints and developing appropriate replacement or refurbishment for such assets;
- Developing, implementing, and evaluating maintenance plans and programs;
- Maintaining and inspecting the Transmission System;
- Undertaking corrective maintenance and emergency repairs of the Transmission System;
- Measuring and analyzing asset management and maintenance results; including the results of capital investment and maintenance plans and programs;
- Monitoring, evaluating, and implementing technological advancements and improvements;
- Managing contracts with Third Parties that are related to the above asset management policies;
- Managing and maintaining the Transmission System as a prudent owner of similar assets would, including forward-looking investment and replacement programs to maintain and sustain the Transmission system; and
- Manage and maintain the Transmission System in accordance with Good Utility Practice.

The Agreement also explicitly states that Commission Orders take precedence if there are any inconsistencies regarding performance standards and/or requirements.

5. Approaches Suitable for Regulators and for Ontario

This section is derived on the basis of the discussion and analysis presented in Section 2 and Section 4 (and supporting Appendices A-F).

- In Section 2, we discussed the key principles of applying effective asset management within network utilities. These principles should be evident within utilities seeking to, or being required/expected to, apply best practice asset management.
- In Section 3, we considered the range of potential assessment methodologies a regulator has access to and their relevant merits in different contexts.
- In Section 4, we have reviewed and compared regulatory approaches actually adopted by a representative selection of international regulators for their assessment of network utility investment plans and underlying asset management practices. This section is supported by extensive material for each of Australia, Germany, Great Britain, New Zealand, the US and Canada (British Columbia) as provided in the Appendices document.

In this Section:

- We first provide an overview of our key observations from KEMA's review of regulatory practices in other international jurisdictions, which highlight the relative difference in contexts and approaches adopted by other regulators.
- Secondly, we suggest a number of options covering regulatory approaches, methodologies, and tools which regulators could apply in their review of utility asset management practices, and resultant network investment plans. It is recognized that, dependent on the specific context of any particular jurisdiction, different combinations will apply and/or be of greater relevance to a particular regulatory jurisdiction.
- Finally, in the third part of this section we identify the regulatory options which may be most helpful to the OEB staff given the current market/industry structure and the regulatory approach in Ontario.

5.1 Summary of Observations from International Comparison

In Section 4, we sought to draw out some key observations and comparisons of the regulatory approaches to assessment of asset management practices (and consequential network investment plans) from the review of a representative sample of international markets. The key characteristics of these markets were also set out to provide context to these regulatory practices.

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Having considered some generically applicable regulatory options for review of asset management in the preceding section, in this section we draw together our view of the key themes and observations which emerged from our review of these international regulatory practices. These are summarized as follows:

- 1) **With one detailed exception, no jurisdiction explicitly requires specific asset management practices nor explicitly specifies compliance with a recognized asset management standard.** Only New Zealand has explicit reference in legislation, namely as part of the information disclosure requirements within the Commerce Amendment Act, which specifically states that an asset management plan may be required. However, all other jurisdictions drive the need for certain asset management practices (and in the case of Great Britain, adherence to the asset management standard PAS 55) indirectly via their expectations of supporting evidence for network investment plans, indicated financial benefits for the network utilities of having such asset management practices, and/or indicated disallowances for not having them. This is typically in the form of degree of acceptance of utility submitted investment plans, and thus, the level of financing; but also can be driven/influenced by utility incentives, such as network performance measures (e.g., Customer Incidents and Customer Minutes Lost).

- 2) **Very different approaches are adopted across the different markets.** For example, the US and Germany are legalistic, whereas Great Britain and Australia/New Zealand are more economic/technical. This finding reflects differences in philosophy on market regulation (including more subtle cultural differences) between the countries, but also the age of the networks (thus degree of escalation in asset related investment) and the level of maturity of network utility regulatory processes (e.g., Great Britain is most mature but Germany is emergent). In addition, some of the technical requirements may sit outside of the economic regulator, which is particularly the case in Australia, where some technical regulation still resides with the States.

- 3) **Varying degrees of regulatory focus on asset management.** Whereas it is a core central aspect of regulatory processes in Great Britain, Australia and New Zealand, it is very limited in Germany, and highly variable in the US markets. This finding is reflected in the rigor of explicit requirements/guidance and the extent of implicit regulatory expectations driving network utility behavior.
 - Great Britain’s regulatory approaches to assessment of asset management represent leading international regulatory practice. Due to contextual circumstances, the evolution of regulatory approaches to review of

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network investment plans, and more recent development of regulatory approaches in relation to underlying asset management practices, have put Great Britain at the forefront of regulatory practices in terms of: a) the central role of asset management practices and consequential investment plans in regulatory review (e.g., via the BPQ process); b) the scope, depth and rigor of related regulatory approaches such as the information requirements in the BPQ and comprehensive review of asset management practices; c) the implicit expectation placed on network utilities to demonstrate strong asset management (e.g., via PAS 55 accreditation); d) development of leading edge methodologies and techniques such as output measures; and e) the wider context of a forward-looking agenda including the development of future network scenarios and the implementation of innovation incentives.

- 4) **Varying levels of depth/sophistication of regulatory assessment.** Great Britain is at the forefront, primarily driven by aged networks and rapidly escalating asset replacement expenditure, but also benefiting from over 20 years of regulation of networks in deregulated energy markets. Germany is the least sophisticated as its regulatory regime is still developing, and also adopts a total expenditure approach to network utility regulation. The US represents a full spectrum of depth/sophistication across their large number of different regulatory agencies.
- 5) **Different approaches to gas versus electric networks.** All the market regulators recognize the inherent differences in the nature of gas versus electricity transportation, and in transmission versus distribution, with the detailed aspects of their regulatory approaches. This fact is further influenced by variation in treatment within overarching legislation (e.g., Health & Safety). Thus, there are variations in processes, information requirements, and areas of key focus within the associated regulatory reviews. There is also a different degree to which aging assets are emerging as a problem in the gas industry compared to the more imminent nature of the problem facing the electricity industry.
- 6) **Different approaches to reflect the scale of utilities.** This finding is evident in the markets where such scale issues are most apparent, such as Germany, and to a lesser extent, New Zealand. It is not applicable to network utility regulation in Great Britain as all network utilities are large, but is applied in other areas (e.g., generation). While the exact difference in treatment between large and small utilities within these markets is specific to those markets and the general regulatory approaches; the key aspect is the reduction in regulatory burden and scrutiny for smaller companies. This manifests itself in a reduction in information requirements and required sophistication of asset

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management practices under both a fit-for-purpose philosophy and a materiality test.

7) **Aspects of regulatory approaches in other international markets also provide key positive learning points.** There are aspects of regulatory approaches in all of the other markets which provide learning points for application in Ontario. This includes:

- The decision by New Zealand to only apply information disclosure and not default price-quality regulation to the small customer-owned distribution utilities. The Energy Minister commissioning the recent Commerce Act review recognized that the owners were also their consumers, and as such, they already have an incentive for a cost minimization rather than a profit maximization model.
- The importance of using third party independent technical experts to review the capital expenditure and asset management plans in Great Britain, Australia, New Zealand, and the US. This approach recognizes the skills needed to do this review are specialized and will be used infrequently as price control reviews emerge. However, it is seen by regulators as an important area with the potential for quite divergent needs for capital expenditure.
- Where the context within which the network utilities are operating or will need to operate is substantially changing and/or there are strong asset management challenges posed by aging network infrastructure. It is clear these are most effectively and efficiently met where the network utilities and regulators have constructive working relationships and focused dialogue on these asset management issues. Good examples of this are Australia and Great Britain.
- Recognition that there can be special circumstances requiring flexibility on the level of price control applied for different companies. This is already seen in the Great Britain and Australian markets where price controls are set for individual companies with a building block approach to the costs, and will identify idiosyncratic features facing particular companies. In New Zealand, with smaller regulated companies, a full building block approach is not seen as efficient for all regulated companies. The intention is that a default price-quality path will be produced using readily available information, but that business can apply for a customized price-quality path where they believe the default approach is not suitable.

5.2 Overview of Key Asset Management Review Practices Regulators can Apply

Within this section KEMA evaluates a number of options for improving assessments of asset management practices. These options are based on KEMA’s review of international approaches and observation of good regulatory practices in the area of network utility asset management.

Some of the options in this section relate to high-level and and/or overarching regulatory approaches; others relate to more specific aspects of regulatory review of asset management. We have tried to provide the appropriate balance of both perspectives and have avoided being unduly exhaustive and prescriptive on detailed implementation issues.

KEMA has grouped the options across two broad dimensions:

- 1) The refinement of the regulatory review process related to asset management practices (i.e., what is done in the process); and
- 2) The strength of regulatory guidance and assessment relative to asset management practices (i.e., how it is done in the process).

The impact on network utility asset management practices of a high or low emphasis placed on either or both of these two dimensions is illustrated below.

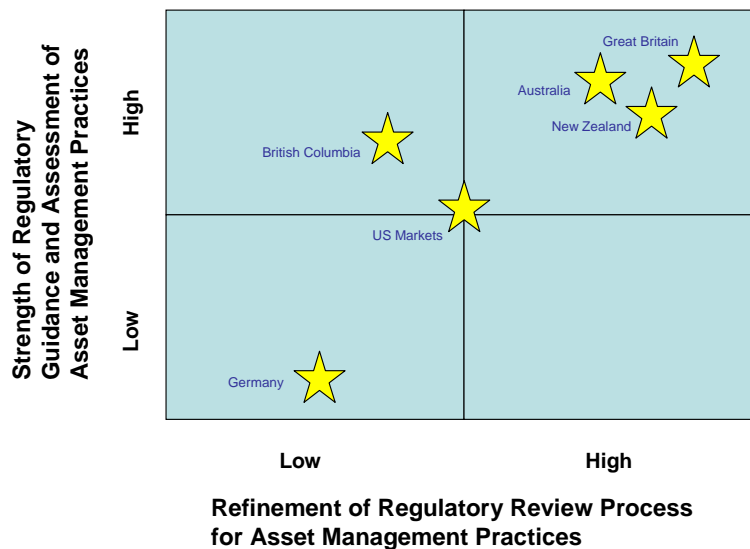
Figure 14: Impact of degree of regulatory review emphasis on Asset Management

Strength of Regulatory Guidance and Assessment of Asset Management Practices	High	Extensive and detailed guidance and assessment requirements encourage strong asset management, but regulatory review process does not place key focus on asset management issues in determination of rates/revenues - has some limited influence on network utility asset management practices; will depend on utility view	Guidance on, and review of, asset management practices is extensive and detailed; with the regulatory review process placing it at the heart of the revenues/rates determination process – this ensures uniformly strong network utility asset management practices at a detailed level
	Low	Asset management is not a focus for guidance or assessment and is a minimal element of regulatory review process in determination of revenues/rates – no influence on network utility asset management practices, which are typically weak	Regulatory review process provides incentives for strong asset management by treating it as a key focus, but level of guidance and/or assessment is limited or conducted at high level – influences good asset management practices based on key principles and objectives; but performance will vary by utility
		Low	High
		Refinement of Regulatory Review Process for Asset Management Practices	

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In this context, the diagram below illustrates the perceived position of the different jurisdiction regulators which KEMA reviewed in producing this report. The y-axis indicates the degree of regulatory engagement on asset management, and the x-axis indicates the relative degree of sophistication of the process. A high y-axis position should not be interpreted as indicating a highly prescriptive approach by the regulator.

Figure 15: Relative position of international jurisdictions/regulators in their emphasis on Asset Management



As illustrated above, the degree to which review of asset management practices forms a key part of the regulatory guidance and assessment of utilities and the regulatory review process will depend on the particular context of the relevant jurisdiction (including the relative maturity of the regulator and energy market) and consequently, the degree to which the relevant regulator(s) wish to focus on network utility asset management practices; and how the regulator(s) wishes to do this. However, where assets are aging or underperforming, and/or investment is large and/or escalating, given that asset management practices will have a strong influence on the associated network utility investment plans, KEMA believes that regulator(s) should ideally apply a combination of types of change to make asset management a key incentivized part of the future regulatory process.

In total, KEMA identified 11 main options which fall into these two categories as listed in the table below.

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Table 20: Options for Improvement to Asset Management Processes in Regulation

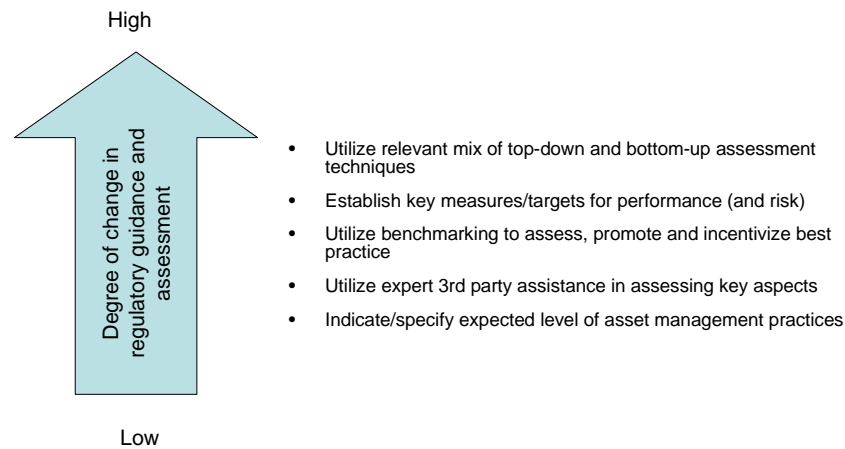
Strengthening of Regulatory Guidance and Assessment <i>(What is done)</i>	Refinement of Regulatory Review Process <i>(How it is done)</i>
1. Indicate/specify expected level of asset management practices.	7. Establish consistency and predictability in process, information and tools.
2. Utilize expert third party assistance in assessing key aspects.	8. Further enhance transparency and engagement of stakeholders in process.
3. Utilize benchmarking to assess, promote and incentivize best practice.	9. Establish regular performance reporting framework.
4. Establish key measures/targets for performance (and risk).	10. Establish periodic cyclical regulatory review of comparable utilities.
5. Utilize relevant mix of top-down and bottom-up assessment techniques.	11. Move away from legal based approach.
6. Apply fit-for-purpose approach based on scale and type of utility.	

Each of the above options has different merits and will have varying degrees of relevance to a regulator, dependent on the particular context of their jurisdiction (e.g., age of network assets, performance of the networks, materiality of network related investment, degree of escalation in network related investment, number of network utilities, size of network utilities) and the regulator position itself (e.g., role of the regulator, form of regulatory framework, size of regulatory staff, knowledge and skills mix of regulatory staff, etc.). Thus, in any given jurisdiction, different combinations of the above options to different degrees of scope, scale, and depth of application, can be adopted by the relevant regulator(s).

5.2.1 Strengthening of Regulatory Guidance and Assessment

There are a number of changes to the regulatory guidance and assessment process that could improve the analysis of asset management processes adopted by utilities. They are listed below in order of the degree of change required by a regulator exhibiting limited focus on review of asset management practices from their starting position (which is a proxy for the ease of implementation).

Figure 16: Degree of Change in Regulatory Guidance and Assessment Options



Each of these options on potential strengthening of the regulatory guidance and assessment dimension relating to network utility asset management and derived network investment plans is discussed in more depth in the following sub-sections.

5.2.1.1 Indicate/Specify Expected Level of Asset Management Practices

A key change that a regulator could easily introduce in the short-term is guidance on their expectations of asset management practices (and efficiency/effectiveness of network investment) to all utilities.

It should be noted that in the context of fit-for-purpose regulatory approach this does not mean all network utilities should necessarily apply identical processes (especially in depth/detail), but that they should adhere to a minimum set of principles/level of performance deemed by a regulator to be appropriate for their peer group. For example, a small utility should not be expected to have adopted the same level of sophistication of systems and processes in its application of asset management practices, but should adhere to key principles of good practice, as outlined in Section 2.

Specification of asset management practices could be achieved both implicitly and explicitly. It could be done implicitly by linking expectation and consequences of achievement or failure against these asset management practices to tangible outcomes such as revenue/rate allowances. For example, in previous years regulators have implicitly taken account of asset management practices/performance in forming a view on network utility investment plans and associated revenue/rate allowances.

5.2.1.2 Utilize Expert Third Party Assistance in Assessing Key Information

If the regulator wishes to pursue a more thorough review of network investment plans and asset management practices, especially within a more periodic and intensive regulatory review process, then international experience suggests that it will be sensible for them to utilize expert third party assistance. This is a key regulatory tool as highlighted in Section 3.3 and extensively used by international regulators as highlighted both in Section 3.11 and Section 4.3.5. Third party assistance is likely to be required in assessing key aspects of network investment plans and underlying asset management practices. The use of such third party resources would provide a number of benefits to a regulator including:

- The regulator will be able to have access to greater resources than it will otherwise be able to apply internally, enabling more thorough review;
- It will reduce the regulator’s reliance on the input of industry parties and lobby groups who typically will have a natural “position” they are seeking to protect (or advance) and thus whose input to the regulatory review process may be colored by this position and related commercial objectives;
- This third party resource will also bring all necessary expertise in specialty areas (e.g., condition assessment, procurement) which may not be fully present (or sufficiently provided) within the regulatory body to enable an expert and effective regulatory review;
- Typically, the third party resource can bring to bear current practices and information from similar work conducted elsewhere in the market and internationally. Often this enables “informed” review of key issues and reduces issues of information asymmetry between regulator and utility;
- Use of a third party enables the regulator to obtain an independent “outside” view divorced from undue influence of any legacy issues/past history at a company or individual level;
- The report can typically be published with the views publicly available to all stakeholders; and
- A useful benefit is that use of a third party allows the regulator to take an alternative view. In other words, the regulator can use the third party review to partly or wholly support its determinations, or can take an intermediary position, thus acting as “honest broker” between network utility and third party reviewer.

There are a number of expert reviewers which are usually available to the regulator both locally and internationally. Some of these parties will cover certain aspects of the regulator’s interest, while others may have more comprehensive capabilities. The key is that the regulator should expect competition for support via a formal tender process, thus should be assured it is getting the relevant expertise and resource it needs at an efficient cost.

5.2.1.3 Utilize Benchmarking to Assess, Promote and Incentivize Best Practice

A fundamental aspect of regulatory approaches in the area of asset management (and more widely within regulatory review of network utilities) is the utilization of benchmarking as a key part of the review process. There are two potential reasons for regulators to adopt benchmarking:

- 1) To establish comparative performance and identify aspects where different utilities under or over perform against their “average” peer comparator; or
- 2) To establish leading practice or performance frontiers to which all peer utilities are challenged to reach.

Each of these approaches has its merits, and the use of one or both by the regulator would be best informed by consideration of the guiding regulatory objectives for the specific regulatory review being conducted and potentially the expertise/advice of supporting third party experts.

Benchmarking can be applied in various ways, including peer utilities within the market, international comparator network utilities and other industry sectors (primarily for HR and IT). In making comparisons, it is important to be aware of distinguishing characteristics such as network topography or urban/rural mix and international difference such as climate and asset age. The assessment can be either purely a quantitative assessment (e.g., unit costs comparison) or a purely qualitative assessment (quality of asset management practices), but often combines both to provide the fullest picture to the regulator. This is particularly important where there may be legitimate differences arising from benchmarking comparisons which pure use of numbers may not make clear.

Typical aspects of network utility investment plans and underlying asset management practices that drive these investment plans can be benchmarked on a quantitative or qualitative basis.

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Table 21: Potential Benchmarking Criteria for Networks

Criteria	Benchmarked Assessment
Capital Spend	Asset base/Number of customers
Unit costs	Capital / Operating spends
Volume of replacement assets	Asset population
Connection costs	Number of each type of connection
Engineering operating expenses	Asset base
Robustness of investment planning process	Options considered, cost/benefit assessments
Robustness of asset management process	Systems, Documentation
Engineering related procurements	Comparative cost of procurement
Actual Capital spend	Forecast capital spend
Actual return on capital	Forecast return on capital
Customer performance	Customer incidents, Customer minutes lost etc
Quality of network performance	Availability of the network, unplanned outages, etc.

Benchmarking has the benefit of providing transparency of performance amongst the network utilities and wider stakeholders, and thus can act as an educator and informer. This is particularly relevant to smaller parties (utilities and stakeholders) who are perhaps less sophisticated than larger parties, and can help drive improvements in performance of smaller utilities. Care does have to be taken with some benchmarking activities to respect commercial confidentialities (e.g., comparison of unit costs).

Benchmarking also has the benefit of acting as a facilitator of peer pressure. This is particularly effective where the regulated network utilities are privately owned and thus exposed to shareholder scrutiny. As such, the company reputation in comparison with peers is important and has financial consequences to motivate network utility executives to seek to be above average or leading performer. It could also be important with publicly owned companies where profit may not be a key objective, but strong technical performance relative to costs may be highly regarded by peers.

Benchmarking is a key regulatory tool as discussed in Section 3.8 and extensively used by international regulators as highlighted in Section 3.11 and evident from Section 4.4 (e.g., Great Britain in Section 4.4.3). Thus, KEMA believes application of benchmarking within the regulatory review of different aspects of asset management practices will provide a regulator with clear benefits in its regulation of both large and small utilities.

5.2.1.4 Establish Key Measures/Targets for Performance (and Risk)

Another key feature of the regulatory approaches that KEMA reviewed are the establishment of key asset management and investment related performance output measures. These measures should be set in line with regulatory objectives and focused on key desired outcomes. Some of these measures may be fixed over time, whereas others may need to be refined as the market context, regulatory objectives, and network experience evolve.

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Measures used by various regulators, in addition to mandatory legislative measures related to Health and Safety, which could be considered for inclusion within a regulatory approach are:

- Customer incident/customer minutes lost performance;
- Worst served customer performance;
- Network losses performance (electricity) and leakage rates (gas);
- Environmental pollution measures (oil leaks, gas leaks, CO₂ emissions, ambient noise, visual amenity);
- Network availability/reliability (unplanned outages; % of full network availability);
- Quality of supply (voltage, frequency for electricity; pressure for gas);
- Number and timeliness of customer connections (volume, lead time, non-compliances);
- Resilience of network to specified extreme (high impact low probability) events such as flooding, storms and degree of resilience (1 in 100 years or 1 in 500 years);
- Resilience of supplies to key network areas, such as central business districts (economic cost benefit of “beyond standards” investment); and
- Network capacity delivery (MW per dollar of investment).

Use of targets and incentives is another key regulatory tool and is evident in international practices as outlined in Section 4.4. For any jurisdiction, a regulator will need to consider which key performance measures most closely align to its regulatory objectives and its desired asset management practices. KEMA would expect some measures to be common across all utilities regardless of size and type (though performance targets/thresholds may vary), but others will naturally be specific to the nature of the network utility (gas or electricity; transmission or distribution).

5.2.1.5 Utilize Relevant Mix of Top-Down and Bottom-Up Assessment Techniques

This is another key regulatory tool used particularly for reviewing the credibility of investment plans put forward by utilities as discussed in Section 3.4. A key lesson from international regulatory experience, particularly that of Great Britain (see Section 4.3.4), is that it is not sufficient to conduct just top-down assessments for distribution networks and just bottom-up assessments for transmission networks where asset management is a focus for review. The regulator needs to apply both top-down and bottom-up assessments for each of the transmission and distribution networks, especially where an increasing and high proportion of network assets are nearing end of life, and thus key decisions need to be made about increasingly material amounts of capital expenditure on asset replacement. This situation is occurring at a time when the nature of technology for both generation and networks, as well as the role of the consumer, is anticipated to change substantially in the next 20+ years.

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As general good practice, a regulator should consider applying both top-down and bottom-up assessment approaches in reviewing the utility asset management practices of network utilities which drive their investment plans. These review activities should include:

Top-Down

Review of asset life determination
Asset replacement modeling
Performance benchmarking
Cost benchmarking
Assessment of investment criteria
Asset management systems
Comparative capital spend

Bottom-Up

Scheme assessments (for a representative sample)
Site visits (to verify asset condition)
Detailed Q&A on processes, information, and data
Review of asset management processes
Review of investment planning process
Evidence of application of asset policies
Comparative spend per investment activity

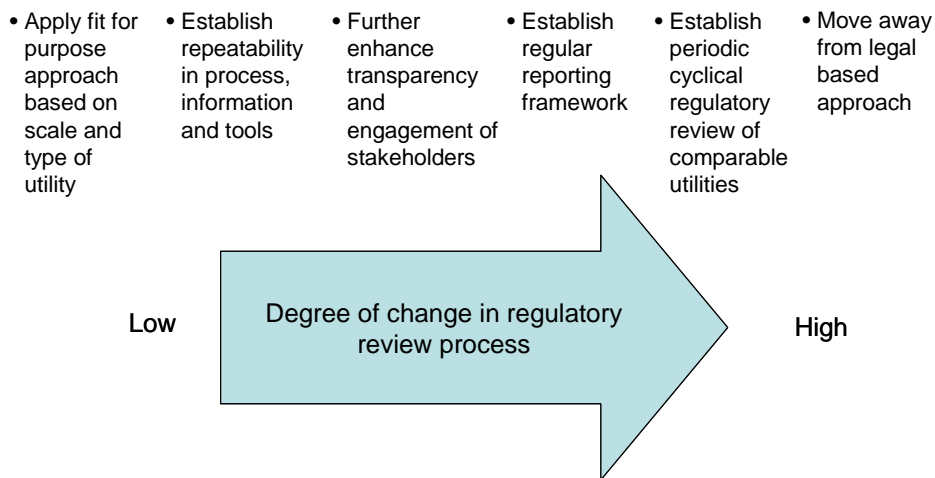
A key aspect of this regulatory review is to understand how the companies marry the two perspectives of assessment within their own asset management practices. For example, what feedback loops exist between: a) observed individual asset condition and assumptions made in asset replacement models; and b) individual outturn scheme costs and forecast scheme costs.

Such an approach is increasingly evident in Australia and New Zealand, but is most evident in Great Britain as highlighted in Section 4.4.3. KEMA suggests any regulator facing submissions for increasing and/or material asset replacement costs look to apply at least some elements of both bottom-up and top-down assessment techniques to assist in its review of asset management practices.

5.2.2 Refinement of Regulatory Review Process

KEMA identified the following potential refinements to the current regulatory review process which could improve the regulatory assessment of asset management processes adopted by network utilities. They are listed below in order of the degree of change required from the current regulatory review process, which will be a proxy for the ease of implementation.

Figure 17: Degree of Change to Regulatory Review Process



Each of these options on potential refinement of the regulatory review process and overall approach is discussed in more depth in the following sub-sections.

5.2.2.1 Apply Fit-for-Purpose Approach Based On Scale and Type of Utility

In general, KEMA recommends that a regulator not seek to simply implement regulatory practices adopted elsewhere without considering the nature/key features of the associated market environment (e.g., numbers and size of network utilities). However, there are aspects of other countries' regulatory approaches that are worth considering, such as the differing degree of regulatory focus applied to utilities of different scale (e.g., specific size thresholds triggering different regulatory treatment). In this example, the approach could be driven by:

- Materiality of network utility investment plans and potential impact on these of different asset management practices;
- Resource capability of organizations to engage in the regulatory process; and
- Incentives for the business to engage in profit maximization versus cost minimization.

Other examples of fit-for-purpose approaches are variations in regulatory treatment of network utilities as a whole or variations in regulatory treatment of different network utilities where, for example:

- There are large numbers of network utilities;
- Network utility companies encompass differing combinations of transmission and distribution and/or electricity and gas networks;
- Owners of network utilities are vertically integrated; and
- Different network utilities have different network topographies (e.g., rural vs. urban) or ages (e.g., due to history of network development).

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In Section 4.4, the different regulatory approaches adopted in each of the jurisdictions reviewed are presented, and these approaches clearly reflect the individuality of each jurisdiction's market and regulatory context. In short, any regulator should seek to implement processes and requirements on a fit-for-purpose basis in the light of its own market and regulatory context. However, wherever possible, the high-level areas for review and key information should remain the same/similar and the variation should be seen in the degree of review and interaction between regulator and network utility. As an example, in New Zealand, all distribution business will be subject to information disclosure, but the price-quality path will not apply to small consumer-owned organizations.

5.2.2.2 Establish Consistency and Predictability in Process, Information and Tools

A key feature in the development of regulatory approaches is the adoption, to the maximum extent possible, of a standardized and consistent/predictable review process. This feature should be targeted at both the high-level design and processes in the approach. The standardized requirements could include information requirements, supporting detailed methodologies and tools.

A consistent, predictable and standardized process has the following benefits:

- It makes the process easier to administer by the regulator;
- It allows for the development of corporate memory (i.e. reducing dependency on key individuals);
- It facilitates the establishment over time of coherent data and information history which can assist in auditing of network utility performance and assessment of future proposals/plans; and
- It ensures comparability of information between peer utilities and can be designed to facilitate international comparison and/or comparison with other industry sectors.

This standardization/consistency and predictability of the process is clearly evident in nearly all international markets outside of North America (see Section 4.4). Consequently, KEMA suggests that all regulators consider developing and implementing standard approaches, methodologies, tools and other techniques which it can apply in regulatory review of both network investment plans and asset management practices. Reference to the Australian or Great Britain market will be useful for detailed examples, including the Business Plan Questionnaires applied in Great Britain. These items can be found on the relevant regulators' websites.

5.2.2.3 Further Enhance Transparency and Engagement of Stakeholders in Process

Most regulatory processes embody a degree of transparency and engagement of stakeholders (Germany is a possible exception). However, often the nature of the process does not easily lend itself to the most effective transparency and engagement of all types of stakeholders

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(especially smaller stakeholders). The benefits of enhanced transparency and stakeholder engagement are clear:

- It increases information and insights the regulator can have at its disposal in regulatory assessments;
- It highlights stakeholder priorities and can thus help to shape the regulator's regulatory objectives and expectations for network utility asset management practices and consequential investment priorities; and
- It provides greater visibility of company actions in relation to stakeholder feedback and acts as a further driver of company action to be seen in responding to the needs of these stakeholders.

Strong focus on the transparency of the review process and assessment of asset management practices is an increasingly key feature of international regulatory practices, as discussed in Section 4.3.5.

A process which is more transparent and accessible to all stakeholders can be further supported by creating stakeholder forums to seek direct views and feedback from these parties. This consultation could be part of the regulatory review process where a stakeholder panel could be created to review and challenge views and information being provided by network utilities in relation to proposed investments and asset management priorities.

Outside of regulatory review itself, a regulator could choose to require network utilities to hold their own stakeholder forums as part of normal business practice, and to feedback stakeholder views in presenting their network investment plans and asset management priorities. This approach is a recent initiative introduced by the Great Britain regulator for electricity distribution companies (see Section 4.4.3) and could form part of an annual reporting framework.

5.2.2.4 Establish Annual Performance Reporting and Monitoring Framework

The establishment of annual performance reporting and monitoring is an emergent feature internationally. As regulatory processes have developed in this area (and also to address wider aspect of network utility reviews) there has been increasing implementation of an annual reporting framework as highlighted in Section 3.11 and evident for Australia (Section 4.4.1) and New Zealand (Section 4.4.3), but is most extensively applied in Great Britain (Section 4.4.3). This reporting and monitoring framework has three key functions:

- 1) Further improves regulatory oversight by providing detailed annual monitoring capability;
- 2) Acts as a bridge between the main periodic price reviews and reduces the need for “starting fresh” every five years; and

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- 3) Highlighting any emergent issues so there are no undue surprises at the next major price review.

This reporting framework is often a formalized process with templates on which the data needs to be provided, and a requirement for directors of the company to confirm the validity of the data submitted. In addition, financial data often requires external auditing. This process should allow for accurate comparison of company data.

KEMA suggests that a regulator considers adopting annual reporting as a complement to periodic regulatory review of network investment plans. Examples of these reporting frameworks are available from Australia, Great Britain and New Zealand. In the case of some of the utilities it may be possible to base any regulatory assessment primarily on the annually produced information, an approach that is being adopted for default price-quality paths in New Zealand.

5.2.2.5 Establish Periodic Cyclical Regulatory Review of Comparable Utilities

Cyclical/regulatory reviews of asset management practices assist in enabling a systematic and effective regulatory oversight/control of utility asset management practices. This feature is discussed in Section 3.5 and it is also a standard international practice outside of North America (see Section 4.3.3 and Section 4.4) to adopt a five year review cycle and seek to review “peer utilities” coincidentally. In markets where network investment plans are reviewed in depth, these reviews are conducted over a substantial time period.

It is suggested that any regulator adopt periodic cyclical reviews of comparable utilities and review all comparable utilities (e.g., electricity distribution companies) together at one point in time. The benefits of this approach are as follows:

- It allows a regulator to conduct an intensive assessment of network utilities’ investment plans and underlying/driving asset management practices over an extended period;
- It allows regulatory focus on similar utilities together – thus ensuring a focused scope of review;
- It enables smoothing of overall regulatory workload by staggering of reviews for different collectives of utilities;
- It facilitates effective resourcing and application of expertise by a regulator to conduct regulatory review, especially where third party assistance is included;
- Regulators can obtain economies of scale and synergies of effort from the commonality of issues to be addressed across the collective utilities;
- It enables effective benchmarking by a regulator of peer utilities amongst themselves and with international comparators and other industry sectors on a common basis; and

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- It facilitates greater transparency of process and easier engagement of stakeholders in the regulatory review process with the regulator through less frequent, more cohesive and more predictable information release and seeking of external input.

The undertaking of cyclical multi-year reviews of comparable utilities does not negate the need to realize that some businesses will have special circumstances (e.g., impacted earlier on by aging assets) and any price control process will need to allow controls to be appropriately tailored to cope with these circumstances.

5.2.2.6 Move Away from Legal Based Approach

Generally, in North America, the regulatory review process is based on a legal approach and does not easily lend itself to an in-depth bilateral expert discussion and review of network utility investment plans and underlying asset management practices. This situation arises for a number of reasons:

- A legal style promotes a “win-lose” environment and can deter network utilities from seeking to engage with the regulator to explore mutually workable “win-win” options;
- The style of process does not easily facilitate dialogue between relevant individuals/interests within both regulator and utilities (e.g., asset management experts);
- The process does not facilitate the degree of contact and iteration between regulator and utility necessary to fully explore issues relating to asset management practices and their consequential impact on/derivation of network investment plans;
- The current emphasis of the process is on tariffs, with a secondary consideration of asset and network performance and risks outcomes whose appropriate treatment could lead to higher/lower tariffs; and
- A legalistic style will deter network utilities from disclosing internal weaknesses of processes and practices and plans for developments.

In general, outside of North America a less legalistic style of regulatory review process and a more interactive bilateral negotiation process is applied. This is particularly evident in markets where the degree of regulatory focus on the justification for network utility investment plans and the effectiveness of underlying asset management practices (e.g., due to aging infrastructure and escalating and highly material investment proposals) has become particularly acute. Of the markets KEMA reviewed in-depth, Australia (see Section 4.4.1), Great Britain (Section 4.4.3), and New Zealand (Section 4.4.4) are good examples of alternative regulatory processes than currently applied in North America.

Consequently, if a regulator wishes to pursue a process which fundamentally increases its focus on the development and implementation of effective asset management practices and

consequentially derived network investment plans, it should consider the merits of moving away from a legal oriented regulatory review approach to a more multi-faceted and engaged process with network utilities.

KEMA recognizes this represents a substantial change from the current regulatory process in North America and would be a long-term option, if a particular jurisdiction/regulator thought this approach was desirable to implement, given likely required changes to the legal and governance framework. However, it may be possible to introduce elements of this into the existing process (e.g., by increasing involvement of engineers and asset management experts in the review process) or as part of a transitional/interim phase towards an ultimate end point of, for example, a periodic cyclical multi-year regulatory review process.

5.3 Suggestions of Potential Regulatory Options for Ontario

This sub-section draws on the preceding material to put forward or suggest potential regulatory options which OEB staff might wish to consider and/or or might find most helpful given the context of Ontario. To set the basis for this, we initially highlight in brief some of KEMA's perceived key characteristics of Ontario in relation to network utilities and their regulation.

5.3.1 Key Characteristics of the Ontario Energy Market

Electricity transmission in Ontario is dominated by one company (owned by the Ontario government) with approximately 97% of the transmission assets. Other utilities also own a small proportion of the electricity transmission assets.

As of 31 December 2007, there were 81 distribution companies in Ontario, although just six of these companies made up 60% of the market share by number of customers. The average line length per company was 2,422KM with the average number of customers of 57,222. If the top six companies were removed from this total, then the average customers per company reduces to fewer than 25,000 and there are 32 companies with less than 10,000 customers - demonstrating the large variability in size. The electricity distributors are mostly owned by the municipal government bodies.

There are three regulated gas distributors in Ontario, consisting of two major companies which between them distribute gas to 3.2 million customers, and a third company distributing gas to an additional 6,500 customers. There are five small gas companies that are exempt from rate regulation and two municipally owned gas utilities that are not regulated. All three of the regulated gas distribution companies are privately owned.

The Ontario Energy Board (OEB) is the single regulatory body in Ontario responsible for regulating natural gas and electricity utilities. Currently, in establishing a rate-setting for a utility, the OEB acts as an adjudicative tribunal and carries out its functions through public hearings, written submission and rule making. The duration of this process will vary

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depending on the type and complexity of the rate application. Target durations are between 185 days for a streamlined written hearing and 280 days for an oral hearing. A major part of the process is the public hearing and the processes around this hearing.

The hearings are conducted in a court like manner, but are not as formal as a court of law. The applicant, the public, and OEB staff can participate in the hearing. There is no requirement to be represented by a lawyer, but depending on the type and complexity of the application the applicant will often be represented by legal council.

A key constituency the OEB regulates is electricity distributors. These companies have their rate plan set for four years under a continuous process with different distributors having the opportunity to re-set their rates each year. As part of the regulatory review, OEB staff requires that capital projects and major operating expenses are justified. However, in recent 2008 and 2009 filings many of the distribution businesses have chosen to include an asset condition study as part of their filing, even though there is no specific requirement to do so.

5.3.2 Potentially Suitable Regulatory Options for Ontario Context

In this section, KEMA highlights some of the regulatory options identified in Section 5.2, which it feels may be most beneficial to OEB staff. Each option is outlined below together with an explanation of why KEMA feels it would suit the Ontario context and would be beneficial for the OEB staff.

1) Apply fit-for-purpose approach based on scale and type of utility

The divergence of types and scales of network utilities as indicated in Section 5.3.1 above emphasizes the requirement for application of a fit-for-purpose approach. KEMA would suggest OEB staff consider differing scope, detail, and intensity of application of asset management assessment within regulatory review of the large network utilities versus that applied for the regulatory review of small network utilities to reflect their relative scale, sophistication, and materiality of impact on customers.

Given the variety of sizes of electricity distribution utilities in Ontario, OEB staff could introduce a regime which is fit-for-purpose in the degree of assessment of different types of utilities, which it is responsible for regulating.

This approach could be driven by:

- Materiality of network utility investment plans and potential impact of different asset management practices; and
- Resource capability of organizations to engage in the regulatory process.

Secondly, the relatively large number of network utilities the OEB has to regulate, compared to Great Britain for example, is a consideration in determining the exact form of application of any/each of the regulatory approaches discussed in Section 5.2.

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In short, OEB staff could seek to implement processes and requirements on a fit-for-purpose basis in the light of the above criteria. However, wherever possible, the high-level areas for review and key information should remain the same/similar and the variation should be seen in the degree of review and interaction between regulator and network utility.

Taking this fit-for-purpose philosophy into account, each of the further options suggested below are those which KEMA feels would suit the Ontario context and would be beneficial for the OEB staff. For each option, we seek to explain the reasoning for inclusion in KEMA's suggestions for OEB staff to consider.

2) Indicate/specify expected level of asset management practices

This is a key change that OEB staff could easily introduce in the short-term. Specifically, OEB staff could issue guidance on their expectations of asset management practices (and efficiency/effectiveness of network investment) to all network utilities. This should be kept to a reasonably high-level.

Such guidance would be especially beneficial given both the size and scale of network utilities in Ontario as it could specify a minimum set of principles/level of performance deemed by OEB staff to be appropriate for network utilities to apply/consider. It addresses the "numbers" issue by providing a low regulatory overhead method of influencing/changing network utility practices. It would also be seen as light touch and advisory so would allow different utilities to adopt changes to differing extents reflecting their varying contexts and priorities in relation to asset management. This is already evident from some electricity distribution companies already submitting asset management plans as part of their rates review submissions.

Furthermore, under a fit-for-purpose regulatory approach, OEB staff could highlight different minimum expectations for extent and detail of processes and approaches which different scales of network utilities should apply (in depth/detail). Thus for example, a small utility should not be expected to have adopted the same level of sophistication of systems and processes in its application of asset management practices, but should adhere to key principles of good practice specified by the OEB staff.

As indicated in Section 5.2.1.1, specification of asset management practices could be achieved both implicitly and explicitly by linking expectation and consequences of achievement or failure against these asset management practices to tangible outcomes such as revenue/rate allowances.

3) Extend use of expert third party assistance to review asset management

If the OEB staff wishes to pursue a more thorough review of asset management practices and consequential network investment plans, it will be sensible to utilize expert third

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party assistance, at least initially. The use of such third party resources would provide OEB staff with access to additional experts that have knowledge of asset management practices both in Ontario and in other jurisdictions and/or industry sectors.

Such expert input could easily be incorporated within the existing rates review hearing process. It would simply mean the addition of a further intervener, and should not be contentious given asset management plans are already being submitted, even though not required under the current review process. The use of such expert third party resources on asset management would also facilitate knowledge transfer to, and thus, strengthen understanding of OEB staff of asset management concepts and practices.

4) Apply benchmarking of asset management practices

This is key tool that OEB staff could apply given the high number of network utilities in Ontario. As indicated in Section 5.2.1.3, it will enable OEB staff to establish comparative performance and identify aspects where different utilities under or over perform against their “average” peer comparator, and if it chooses to do so, also establish leading practice or performance frontiers to which all peer utilities are challenged to aspire to.

This application of benchmarking may be hampered by the fact that not all distribution companies have their rates reviewed simultaneously. Consequently, OEB staff might wish to conduct an initial such benchmarking exercise outside the ongoing rates review process and then seek to roll it into future rate case reviews.

As indicated in Section 5.2.1.4, benchmarking can be applied in a number of ways and has potential pitfalls if not applied in an informed manner. Consequently, OEB staff may need expert third party assistance to conduct an initial benchmarking exercise until it develops its own understanding of application of benchmarking to provide accurate and meaningful comparisons.

5) Establish consistency and predictability in process, information and tools

KEMA suggests that OEB staff consider the adoption, to the maximum extent possible, of a standardized and consistent/predictable review process. This should be targeted at both the high-level design and processes in the approach. The standardized requirements could include information requirements, supporting detailed methodologies and tools. This has the following benefits:

- It makes the process easier to administer by OEB staff – useful given large numbers of utilities to regulate;
- It allows for the development of corporate memory (i.e., reducing dependency on key individuals);

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- It facilitates the establishment over time of coherent data and information history which can assist in auditing of network utility performance and assessment of future proposals/plans; and
- It ensures comparability of information between peer utilities and can be designed to facilitate international comparison and/or comparison with other industry sectors.

Consequently, KEMA would suggest that OEB staff consider developing and implementing standard approaches, methodologies, tools, etc., which it can apply in regulatory review of both network investment plans and asset management practices. If adopting this approach, then reference to the Australian or Great Britain market will be useful for detailed examples including the Business Plan Questionnaires applied in Great Britain. These can be found on the relevant regulators' websites.

However, it is important that OEB staff apply such standardized, consistent and predictable processes in a manner which is fit-for-purpose for Ontario. Specifically, it is important to recognize the different scales of utilities which the OEB regulates. As such, it may be appropriate to adopt, for example, two different forms of standardized processes for each of the large network utilities and the small network utilities, as collective groups. Clearly, there would also need to be further distinction (as evident from similar processes in Australia and Great Britain) of the detailed processes applied to different types of network utilities (electricity vs. gas, and distribution vs. transmission).

6) Establish annual performance reporting and monitoring framework

Finally, the establishment of annual performance reporting and monitoring is an emergent feature internationally. KEMA suggests that OEB staff consider adopting annual reporting as a complement to periodic regulatory review of network investment plans. Examples of these reporting frameworks are available from Australia, Great Britain and New Zealand. KEMA suggests that OEB staff consider implementation of its own annual performance reporting and reporting framework as it has a number of benefits in the Ontario context:

- It enables easier regulatory review of the relatively large numbers of Ontario network utilities, and by default, enables benchmarking to be more easily conducted as information is gathered in the same format at the same time;
- It maintains scrutiny on the subset of large network utilities which have material impact in terms of cost or performance on customers;
- For individual network utilities it acts as a bridge between the periodic Rates Reviews and reduces the need for “starting fresh” every four years – thus easing regulatory burden and helping maintain “corporate memory”. In the case of some of the smaller network utilities such a reporting framework can make it possible to base regulatory assessment primarily on the annually

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produced information and, as indicated previously, this is an approach being adopted for default price-quality paths in New Zealand; and

- It flags any emergent issues such that there are no undue surprises at the next major rate review (e.g., where there are deviations in expenditure from submitted investment plans or expected asset/network performance).

Ideally, this reporting framework should be a formal process with standard templates on which the data needs to be provided and a requirement for directors of the company to confirm the validity of the data submitted. In addition, external auditing could be used to ensure veracity of the data submitted.

The reporting framework should seek to address the full scope of network utility activities. However, recognizing that initial set-up may be onerous, and given the large number of utilities that the OEB has to regulate, it may be useful in the first application of such a reporting and monitoring framework to focus on the main areas/aspects which OEB staff is most interested in/concerned about. Furthermore, OEB staff may wish to consider varying the scope and detail of such an annual reporting requirement by scale of utility (i.e., the large network utilities might be expected to report more information and in greater detail than smaller network utilities on the grounds of materiality of impact) – though there should be a degree of consistency/commonality to enable full comparison across peer group network utilities (e.g., all distribution companies regardless of size).

KEMA believes these six suggested aspects would be of particular benefit to OEB staff, given the Ontario market context. However, clearly OEB staff is in the most informed position regarding its regulatory priorities, and as such, the above are put forward as suggestions rather than recommendations. We would anticipate that OEB staff will review all of the identified potential regulatory approaches, methodologies and tools which are evident to a greater or lesser degree in other international jurisdictions, as addressed within this overall Report and supporting Appendices, and form its own view as to what best suits Ontario and the OEB.

5.3.3 Evolution of Regulation Given Experience and Changing Context

Notwithstanding the above, KEMA suggest that in implementing new regulatory approaches the OEB staff seek to roll out new process, methodologies and tools in a manner which enables expansion of scope and depth over time without requiring fundamental change in approach or application. While the OEB staff should seek to retain the benefits of commonality of approach and consistency and predictability of process, it should not stick to a rigid process which does not fit market context and/or regulatory experience.

This approach to evolution of regulatory approaches to fit context and priorities has been observed in the international markets. This will best enable OEB staff to:

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- Fit evolving market context (political, environmental, economic issues, etc.) and thus evolving regulatory imperatives; and
- Use the benefit of experience and increased knowledge of asset management, its impact on network investment plans and impact on stakeholders.

KEMA cannot provide any specific recommendations at this stage for this evolutionary process given OEB staff will determine the detailed starting point. However, two examples of the evolutionary approach are as follows:

- 1) Initially adopt a small set of the most important high-level performance measures for network utilities and use observation of their performance to determine how these should be made more detailed and how they should be expanded; and
- 2) Introduction of incentives should be initially weak in strength and narrow in scope focusing on the priority issues at a high-level. Again, these can be progressively strengthened and expanded as experience in their use is gained and data history developed to avoid inadvertent perverse or undesired consequences driven by the incentives (arising from their individual complexity or mutual interaction).

5.3.4 Assessment Criteria for Consideration by OEB Staff

The table below identifies a series of wider factors that a regulator might wish to consider when evaluating the introduction of new asset management policies.

Policy Assessment Criteria		
For the new policy being considered....		
1	Does the regulator have the legal vires to implement this?	
2	Will the implementation proposal be sufficiently robust to external challenge?	<ul style="list-style-type: none"> - Availability of a Regulatory Impact Assessment - National or International benchmarks or references - Hard evidence not simply 'best judgment'
3	Is this proposal consistent with other policy developments?	
4	Is the regulatory burden understood and accepted?	<ul style="list-style-type: none"> - Resources - Budget - Specialist skills - Need for external support

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5	Have the reporting requirements been assessed and deemed acceptable?	<ul style="list-style-type: none"> - Data volumes - Practicability of reporting time-cycles - Workload peaks/troughs
6	Will the policy enhance the desired style of relationship with the regulated companies?	<ul style="list-style-type: none"> - balance of responsibilities and accountabilities - tendency for regulatory micro-management - company proactivity
7	Where are the companies now as regards proactive behaviours; how will they respond?	
8	Does the policy have longevity; should it be implemented in stages?	<ul style="list-style-type: none"> - ability to adapt or extend - modify in light of experience
9	If incentives are proposed, is the data sufficiently robust?	<ul style="list-style-type: none"> - to audit standard if finance consequences - consistency of data definitions between peer companies
10	Scope for company gaming; regulatory counter-moves?	

The factors in the table above include a range of regulatory perspectives and these are clearly “context specific” and to some extent a matter of regulatory preference. They include the important, but hard to define, issue (item 6) of the desired form of regulatory relationship with the network companies. For example, having rigid asset management frameworks and close regulatory oversight, may have the advantage of initial regulatory comfort, but are unlikely to encourage flexibility, open dialogue, risk management and entrepreneurial thinking in the companies. In the extreme case they may lead to risk aversion and a dependency culture where the “regulator does the thinking” and therefore “takes the risks”.

The approach by Great Britain seeks to maintain an effective relationship between the regulator and company, where responsibility and accountability are clearly with the asset owner, but due regulatory oversight is not foregone. This effective relationship is in part fostered by the policy approaches adopted and, less visibly, by the style of interaction between senior people on both sides. Ofgem deploys a range of inter-personal approaches and ensures that senior managers in the companies take personal accountability in regulatory reviews, including face-to-face meetings with the Ofgem board (the Gas and Electricity Markets Authority). It can be an effective lever to minimize the likelihood of regulatory gaming, which would require company senior managers to give a personal explanation for company behaviors in front to of an eminent peer group.

Appendices – Review of International Markets

In producing this Report for the OEB staff, KEMA drew upon extensive review of regulatory approaches adopted for assessment of network utility investment plans and underlying asset management practices for a selection of international energy jurisdictions; namely:

- Australia
- Germany
- Great Britain
- New Zealand
- USA (overview of intra-US markets)
- Canada (British Columbia)

For each of the above markets KEMA provided detailed information regarding:

- Characteristics of utilities affected;
- Assessment of utility investment plans;
- Regulatory information requirements;
- Explicit asset management requirements;
- Relevant regulatory instruments;
- Regulatory guidance to utility companies; and
- Lessons learned and future areas of focus.

This information of the each of the international markets highlighted above has been collated and provided in a stand-alone Appendices document to this Report; which has been provided separately to the OEB staff.